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June 13, 2003

via MESSENGER

Jeffery Kitsembel
Public Service Commission
P.O. Box 7854
610 North Whitney Way
Madison, WI 53707-7854

RE: Power The Future – Phase II
PSC Docket No. 05-CE-130

Dear Mr. Kitsembel:

Attached are the comments of Wisconsin Electric Power Company, W.E. Power, LLC, and Wisconsin Energy Corporation (the companies) on the Draft Environmental Impact Statement in the above docket, issued by the Commission on April 28, 2003.

It is important to note that the companies are extremely cognizant of the tremendous amount of investigation and review required by the state agencies involved in this process, the Public Service Commission of Wisconsin and the Department of Natural Resources. Both agencies participated in public meetings to gather additional comments. The Public Service Commission staff had the responsibility of gathering, organizing and issuing the Draft Environmental Impact Statement ("DEIS"), incorporating the wide range of impacts of this significant and important project. We believe that the DEIS fully and comprehensively considers the environmental impacts of the proposed action consistent with the requirements of §1.11, Stats. The companies appreciate those efforts and believe the record in this case will be enhanced because of them.

The comments enclosed fall into several categories. First, some comments address facts or calculations which may have been misstated. Second, there are comments which address interpretations of data or information. Third, we have provided certain information related to the accommodations identified as a result of input from various stakeholder groups and detailed in the testimony filed on May 27, 2003. Finally, certain information has been provided regarding other planned projects, particularly at the Oak Creek Power Plant, which may have impacts over the entire system or at the Elm Road site.

Even though additional information has been provided regarding the impact on the aggregate emissions of Wisconsin Electric's fossil generation fleet from future pollution control efforts at its existing generation, the company is not requesting approval for any projects other than the 1800 MW proposal for Elm Road Generating Station. Further, our comments do not indicate any request for approval of a scope of work other than that identified in the Company's original request for the Elm Road project. These comments are provided for the Commission's convenience and information, not as a requirement for the DEIS. However, we believe the impacts of the emission reductions, which will be addressed at the hearing, are important to the Commission's decision-making in the proceeding.

Copies of these comments will be served on all parties in accordance with the procedures directed by the Law Judge.

Thank you for the opportunity to comment on this important document, and for your consideration of those comments.

Very truly yours,

R. A. Draba
Vice President-State Regulatory Affairs

encls.
/rmr

cc: Service List (w/encls)

Executive Summary (p xix)

Under the leased generation approach, WEPCO would enter into a long-term facility lease with its non-affiliate company known as WE Power. WE Power would construct and own the facilities, but lease the generating units to WEPCO and other interested utilities at economic terms and conditions reviewed, regulated, and approved by the PSC. WEPCO would operate the coal facilities at the ERGS. Operation would include staffing, maintenance, and fuel procurement.

Comment: It would be more accurate to state this as follows:.

Under the leased generation approach, WEPCO would enter into ~~a~~ long-term facility leases with wholly owned subsidiaries of its non-affiliate company ~~known as~~ WE Power. WE Power's subsidiaries (ERGS SC LLC and ERGS IGCC LLC) would construct and have the ownership interest in the facilities, but would lease the generating units to WEPCO ~~and other interested utilities~~ at economic terms and conditions reviewed, regulated, and approved by the PSC. Other interested utilities might have ownership interests in the facilities as well, but the WE Power companies will ultimately own no less than 83% of each of the new units. WEPCO would operate the coal facilities at the ERGS. Operation would include staffing, maintenance, and fuel procurement.

(p xx) Suggested change: IGCC cost estimates are less certain because coal-based IGCC plants in the 500+ MW range have not been built anywhere in the world.

Comment: This is only true for coal based IGCC plants. Two heavy oil IGCC plants in Italy (ISAB 520 MW, SARAS 550MW) entered commercial service in 2001. This information was included in 1-SUP-166.

(p xxii) Executive Summary

On March 25, 2003, the city of Oak Creek and WEPCO entered into an agreement by which WEPCO agrees to annually pay the city of Oak Creek $1.5 million at the start-up of ERGS unit 1…The first annual payment of $1.5 million would increase the cost of the facility lease for the first SCPC unit by about 1.5 percent based on an annual estimated lease payment of nearly $107 million.

Comment: $1.5 million divided by $106.9 million = 1.4 percent, not 1.5 percent. Further, the impact of $2.25 million divided by $214 million for the first two plants combined is less than 1.1 percent.

(pxxiii), first par., last sentence. Comment: WEPCO reserve margin 20.56% per MAIN audit.

(p xxvii) Comment: Please consider the following correction.

The primary soil stockpile locations described in the application include:

- an area east of STH 32 south of the existing transmission line corridor;
- an area north of Elm Road across the railroad tracks from the Barton Oaks subdivision that is currently old field, ~~and~~ wetlands, and the North Ash Landfill;
- a large area immediately south of Haas Park that currently supports the Oak Creek ~~North~~ South Landfill;

(p xxx) Solid Waste

Comment: Change quantities because of the updated bituminous coal characteristics (Washed Pittsburgh #8) as follows for the SCPC units:

165,200 tons per year of fly ash changes to 206,300 tons per year
38,600 tons per year of bottom ash changes to 51,600 tons per year
137,666 cubic yards per year of fly ash changes to 171,900 cubic yards per year
32,166 cubic yards per year of bottom ash changes to 43,000 cubic yards per year
169,832 cubic yards per year of total volume changes to 214,900 cubic yards per year

Change quantities for the IGCC units based on more detailed information as follows:
18,000 tons per year of elemental sulfur changes to 33,200 tons per year
60,000 tons per year of sulfuric acid changes to 109,200 tons per year
62,400 gallons per day of sulfuric acid changes to 50,700 gallons per day
200,000 gallons of on site storage remains the unchanged.

(p xxxviii) primary stockpile locations. Correction: The second bullet should read …that is currently old field, wetlands, and the North Ash Landfill. Third bullet should read….supports the Oak Creek South Landfill.

(pp 1, 6 & 31) **Description of the Proposed Project.** Comment: Suggest correcting typo in last paragraph as follows.
In order to meet this need, plus an 18 percent reserve margin, it has proposed a package of generation capacity that includes 1,090 MW of natural gas-fired capacity at its existing Port Washington Power Plant site and ~~1,860~~1,830 MW of coal-based generation that is the subject of this application.

(p 2) Proposed sites Comment: Suggest clarifying first paragraph as follows.

The proposed sites for the ERGS are on a large parcel of land located along the shore of Lake Michigan near the OCPP. The parcel is approximately 1,000 acres in size, and is primarily owned by WEPCO. This land currently functions as buffer area around the existing OCPP. A ~~federally owned 7~~80-acre property within the WEPCO property is currently used as a shooting range, but is also being considered as a site for some of the facilities. The property consists of two parcels - a northerly parcel owned by the State of Wisconsin (28.92 acres) and a southerly parcel owned by the U.S.A. (51.08 acres).

(p 9) Table 1-2 Comment: CPCNs will be needed for transmission.

(p 13, par. 2 and Executive Summary, p xx) "WEPCO provided the costs for the ERGS as part of its overall PTF application. However, the costs provided for ERGS are not as certain as those provided for the Port Washington units. The costs provided for the SCPC units are somewhat uncertain and the cost for the IGCC unit is even less certain. Thus, the estimated costs for the ERGS are on a "cost-plus" basis, rather than a "firm" basis like the Port Washington costs."
Comment: Please use the more accurate term "Cost Reimbursable with Cap."

(p 14) Suggested change: In addition, IGCC cost estimates are less certain because coal-based IGCC plants in the 500+ MW range have not been built anywhere in the world.
Comment: This is only true for coal based IGCC plants. Two heavy oil IGCC plants in Italy (ISAB 520 MW, SARAS 550MW) entered commercial service in 2001.

(p 15) Suggest changing "Bechtel Engineering" to "Bechtel Power Corporation."

(p 15) "Items that could impact or increase the original estimate provided by WEPCO include:"

Comment: All capital costs items listed are included in WE Power's estimate provided in the direct Testimony of Mihm with the exception of transmission (ATC costs) and City of Oak Creek payments (not capital). Also coal shed estimate is $20 million not $5 million.

(p 16) The cost for one of those plants, the Wabash River Plant in Indiana, was $417 million for a 262-MW facility (in 1995 dollars) or $1,591/kW.
Comment: According to the response to 1-SUP-166, Wabash was $438 million for a 260 MW plant (in 1995 dollars) or $1,685/kW. However, this was a repowering of an existing coal fired unit. Because of re-use of existing plant equipment, it is not directly comparable to other projects. Allowing for new equipment, the estimated cost would be $29 million higher. This would result in a cost of $1,796/kW. Costs are higher because of the interpretation of capital costs versus capital costs.

A DOE report entitled "Wabash River Coal Gasification Repowering Project, Final Technical Report, August 2000" states "The installed cost of the overall IGCC facility including start-up was about $1590/kW (1994$). Allowing for new equipment that would have been required if this had been a greenfield project instead of repowering, the installed cost figure on this demonstration project was $1700/kW (1994$).

(p 18) Suggest the following change:
In Wisconsin, several generation projects that preceded the ERGS proposal in the ATC queue have been cancelled, or indefinitely delayed. At the time that the initial interconnection study for the ERGS was completed, there were other units in the Midwest queue ahead of Elm Road, including IC001 (Badger Gen – Kenosha~~Midwest Power – Germantown~~) and IC003 (~~Badger Gen – Kenosha~~ Midwest Power – ~~Germantown~~New Berlin) and four generating units in northern Illinois.

(p 22) Chapter 2, **Figure 2-4**
Comment:

The facility lease relationship shown as A between the ERGS SCPC 1 LLC and the Other Investors is included in the diagram in error. The description for that symbol also erroneously mentions "two secondary Lessees". There will not be a lease between ERGS and Other Investors; the facility lease will only be between ERGS (as Lessor) and WEPCO (as a single Lessee). There might be a facility lease between the "Other Investor SPE's" and the "Other Investors", but such a lease is not the subject of the Applicants' filings in either Docket No. 05-CE-130 or Docket No. 05-AE-118.

Further, the party labeled "W.E. Power SCPC1 LLC" should be renamed "ERGS SC LLC" and the subsidiary labeled "ERGS-SCPC 1 LLC" will not exist. The ERGS SC LLC will have an ownership interest somewhere between 83.34% and 100% in the Unit 1 facility. The lease agreements are between WEPCO and ERGS SC LLC, not between WEPCO and the Unit 1 facility.

(p 24) Chapter 2,
In a July 19, 2002, agreement with the Customers First Coalition, an intervener group representing a variety of consumer groups, WEPCO agreed to seek financing for the coal facilities using a 12.9 percent return on equity and 55 percent common equity in the capital structure.

Comment: The July 19, 2002 stipulated agreement covers the two proposed PTF gas units at Port Washington. It is silent as to the terms that would be proposed for the coal units at the Elm Road site.

Given the facility lease payment calculation shown above, it is possible to estimate the effect on ratepayers for the two SCPC plants. Together, the annual lease payments would equal about $214.million. Presently, the retail electric revenue requirement for WEPCO is $1.7 billion. By 2007, WEPCO's retail revenue requirement may equal $2 billion. This means that the additional lease payments for the first two SCPC plants at Elm Road would increase retail electric revenue requirement by about 10.7 percent.
Comment: In 2007, while WEPCO's retail revenue requirement may equal $2 billion, only one of the SCPC units will go into service and it will not go into service until mid-year. Thus, for 2007 the rate impact would be 2.7%, not 10.7% (($107 million/2)/$2 billion).

For 2008 the revenue requirement would increase (assuming a 2.32% inflation factor) but the lease payment would remain the same, for a net impact of ($107 million/($2 billion * 1.0232%)) = 5.2% compared to 2006 rates. The increase in rates from 2007 to 2008 is only 2.6%.

For 2009, the second SCPC unit would go into service mid-year. The net impact for that year would be ($107 million + 107 million/2))/($2 billion*1.0232^2) = 7.67% when compared to 2006 rates. The increase in rates from 2008 to 2009 is only 2.6%.

When both plants are in service, in 2010, the net impact would be ($107 million*2)/($2 billion*1.0232^3) = 9.99% when compared to 2006 rates. The increase in rates from 2009 to 2010 is only 2.5%.

Because the lease payment remains fixed, the rate impact thereafter declines as the overall revenue requirement increases.

The estimate does not include carrying costs or interest during construction.

Comment: One cannot include carrying costs or interest during construction to the estimated future rate impacts because those costs are being paid by the utility (and recovered in rates) during construction. This was intentionally established by the parties in the lease in order to mitigate future rate impacts.

(p 31) , 5th Par. Please consider the following changes.
The PSC has traditionally ~~required~~ recommends Eastern Wisconsin utilities ~~to~~ maintain a higher 18 percent planning reserve margin due to concerns with issues such as transmission limitations. The Mid-America Interconnected Network (MAIN) guidelines typically ~~require~~ recommend about 15 percent target reserves.

(p32) Note (2 places): MAIN audit results show 20.56% reserve margin.

(p 37) Comment: Suggest the following changes to Table 3-2.

Table 3-2 Generating units installed by or under contract to WEPCO since 1985

1997	Whitewater combined-cycle (purchase)	235	~~288~~247
2000	Neenah combustion turbines (purchase)	300	350
200~~4~~3	Zion combustion turbines (Illinois purchase)	450	

(p 37) Comment: Suggest the following change to the 2nd par.
In addition to the generating units it built, WEPCO arranged a 235 MW power purchase from the Whitewater combined-cycle generating unit and it expects to use up to 450 MW of capacity from Calpine's Zion Energy Center in Illinois by ~~2004~~2003.

(p 38) Comment: Consider the following title revision.
Table 3-3 Other generating units greater than 50 MW installed ~~in Wisconsin~~ since 1998 (or under construction)

(p 38) Comment: Consider the following changes.
During the summer of 2000, SEI Wisconsin, ~~an affiliate~~the predecessor of Mirant, placed a 300 MW natural gas facility in Neenah into commercial operation (the plant subsequently purchased by ~~WP&L~~Alliant Generation). During 2001, the 450 MW RockGen combustion turbine project located in the town of Christiana in Dane County began full operation. All of these facilities are under contract to various state utilities. The sale of some of the merchant power plants to Wisconsin utilities reduces the amount of generation that merchant plants were predicted to supply toward the state's generation needs.

By the end of 2004, nearly 2,050 MW of electric generating supply being used by electricity providers for Wisconsin customers may come from merchant plants under contract to the states utilities. Some of this power will come from merchant facilities located outside the state; such capacity plays an important part in maintaining electric reliability in the state. For instance, by ~~2004~~June 2003, WEPCO expects to use up to 450 MW of capacity from Calpine's Zion Energy Center in Illinois.

(p 43) Suggest the following change:

Planned capacity retirements and nuclear relicensing

WEPCO has indicated that no existing baseload capacity would be retired in the near future. Commission staff recommended considering retirement of a generating unit at 60 years and this assumption was incorporated into the EGEAS modeling. This would allow retirement of Oak Creek Unit 5~~1~~ in 2019.

(p 48) Comment: Suggest revising the last paragraph as follows.
An alternative way to depict the information in Figure 3-14 is to examine the expected planning reserve margin for WEPCO if the capacity represented by the Port Washington and ERGS units is added to the existing system. Figure 3-15 portrays expected planning reserve margins with or without the Port Washington and ERGS units. Presently, the PSC ~~requires~~ recommends the state's utilities to maintain an 18 percent planning reserve margin.

(p 59) **Renewable Resources as an Alternative**

In Wisconsin, the noncombustible renewable resources in use for electric generation are wind, solar and hydro. Combustible renewable resources include fuel cells fueled by hydrogen that is produced by a renewable resource and biomass energy derived from wood or plant residue, biological waste, crops grown for use as a resource, or landfill gas. The main renewable energy resources for Wisconsin electric generation appear to be wind power and biomass fuels, including waste-to-energy. At this time, solar power appears too costly to install on a utility scale and there is very little additional hydroelectric power potential available in Wisconsin.
Comment: Please change the third sentence in the above paragraph as follows:
The main new renewable energy resources for Wisconsin electric generation appear to be wind power and biomass fuels, including waste-to-energy.

(p 59 last paragraph)Comment: Suggest revising as follows:
Blades are shaped and positioned to take advantage of different wind velocities so that, depending on design, one wind machine may produce power in a different range of wind velocities than another. Power output is ~~directly~~ proportional to the square of the length of the blades. Cold air is denser, which means it ~~has more force, or ability to turn the blades~~is heavier, than warm air. A wind machine in Wisconsin's cold, dense winter air can produce up to 20 percent more than the same machine with the same wind speed but in ~~warmer~~ hot summer air.

(p 60) Clarifying Comment:
Table 4-1 shows potential capacity and electrical generation based on the land area exhibiting each class of wind speed and assuming 12 MW per square mile.41 The numbers in 4-1 do not include potential offshore wind development in the Great Lakes because the greater projected cost per MW and greater O&M cost ($1671 per MWh and $33 per kW-yr.). Wind power imports from neighboring states with superior wind regimes are also not included due to severe transmission constraints.

(p 61 first paragraph)Comment: Suggest revising as follows:
Factors affecting property values ~~including~~ include the general condition of the local and national economy, taxes, the reputation of the school system, and the availability and condition of infrastructure (i.e. roads, police and fire protection).

(p 61) Comment: Please consider the following revision to include pertinent factual information.
From a social and economic standpoint, wind power has several advantages. Wind energy generally requires a larger workforce than typical gas fueled combustion turbine technologies but less than typical coal fueled facilities. From an economic standpoint, wind power does not have any associated fuel-price risks. Because wind power requires no fuel, the cost of wind generated electricity would not be affected by volatility in fuel prices.

(p 62 Table 4-2)Comment: Suggest using "lb." instead of "#".

(p 62 Sentence following Table 4-2)Comment: Suggest revising as follows:
At an 85 percent capacity factor, ~~22,547,000 MWh~~ 3028 MW would yield ~~3028 MW~~ 22,547,000 MWh of energy per year.

(p 63)Comment: Suggest revising as follows:

3. Woody or herbaceous energy crops—grown ~~sustainable~~sustainably on cropland or in plantations and dedicated for conversion to electricity.

(p 66) Comment: Suggest revising as follows:
Another important assumption in the EGEAS runs is the 20 percent credit to reserve margin. This means that for every 100 MW of wind power generated, only 20 MW would be credited toward WEPCO's reserve margin. This is somewhat conservative in light of the Mid-Continent Area Power Pool (MAPP's) wind accreditation reporting for 2000 through 2001, indicating that five wind farms in Minnesota had accredited capacities ranging from 21 to 29 percent. However, those wind farms are located in stronger wind regimes than Wisconsin has.

(p 69) Comment: Please consider the following qualifications to the last paragraph.
The Calpine proposal submitted to the PSC does contain a ~~completed~~ sample power purchase agreement (PPA) with relevant economic and engineering terms and conditions determined solely by Calpine. Such terms and conditions, due to their trade secret nature, have been filed confidentially at the PSC and are available only from Calpine after entering into an appropriate trade secret protection legal framework.

(p 83) **Chapter 5 - Fuel Diversity Perspectives** Comment: Suggest adding to the second paragraph as follows.
Some of these considerations include: the age and condition of WEPCO's existing generating units; the source and availability of the fuels; fuel prices and the expected stability or volatility of fuel price over time; overall energy balance in the State of energy use in all applications; and the environmental effects and safety issues associated with the use of different fuels.

(p 85) Comment: Suggest adding to the 3rd paragraph, last sentence as follows.
This suggests that even though large volumes of natural gas continue to be consumed, the available resource base may be expanding, not declining, as gas prices move higher. Over the long term, existing production areas will not be able to supply the increases in demand. Gas will need to be brought to market from areas that currently have little or no production because of cost, technology or regulatory reasons. Examples include importing LNG, offshore eastern Canada, the Mackenzie Delta, Alaska and the Rocky Mountains.

(p 87) Comment: Suggest citing the demand forecast that shows a slowing as stated in the following.
With the generally slow growth rate in natural gas demand and the apparent slowing in the pace of natural-gas- fired electrical generation, technological advance and technological innovation could allow for the development of additional supplies to keep pace with the demand for natural gas.

(p 89) Comment: Suggest adding to the 3rd par., the following.

When the number of operating rigs is not sufficient to keep up with demand, ~~two~~ three things happen: (1) interruptible customers do not receive natural gas ~~and~~ , (2) natural gas prices rise and (3) demand destruction occurs. So during these situations for the generator using natural gas, supplies might be available at high cost, or under certain conditions might not be available at all.

(p 91) The recently-constructed Guardian Pipeline is such an example. It brings an additional 750 dekatherms per day of capacity to the state, some of which could be used to serve natural-gas-fired electric generators.
Comment: Instead of dekatherms, the unit of measure is million cubic feet. The same error is repeated in footnote 67.

(p 93) Coal mining and transport, 3rd par. Comment: Please consider the following change:
To grasp the impact coal mining has had on the environment, one can examine the statistics for Pennsylvania, the ~~second~~ fourth largest coal-producing state in the U.S. and the source of the coal to be used in the ERGS facilities.

(p 95) **Chapter 5 - Solid Waste**
Comment: Change quantities because of the updated bituminous coal characteristics (Washed Pittsburgh #8) as follows for the SCPC units:
165,200 tons per year of fly ash changes to 206,300 tons per year
38,600 tons per year of bottom ash changes to 51,600 tons per year

In the fourth line the word "acid" should be deleted or changed to "ash". Leachate from coal ash is typically basic rather than acidic.

(p 101) Comment: par. 5 refers to an existing rail loop. There is currently no "loop." The existing track curves onto the property, but terminates rather than reconnecting with the UPRR tracks.

p 101 par. 6. Comment: There are two existing storage piles, one on the dock as mentioned, and one east of the car dumper.

p 102 Comment: par. 3 States generating station equipment would occupy about half of the site. If this is referring to the 1000 acre site, then it is incorrect. Also included with balance of the site would be existing landfill areas, which cover a large portion of the 1000 acres.

(p 102) Note: par. 7 Comment: Outdoor piles will occupy 22 acres of land. Apparently, the Staff's calculation did not consider the irregular shape of the coal piles. Please consider the following revision.

The new coal piles would occupy approximately ~~55~~ 22 acres of land ~~with a footprint of approximately 1,425 by 1,650 feet~~, exclusive of the various conveyors.

(p 102, par. 8) Comment - semantics: A *harbor* is required for ship delivery of coal only. The *expansion* is used for limestone and gypsum loading, unloading, and processing, even if ship delivery of coal is not the chosen fuel delivery method.

(p 109) Comment: Please revise the first sentence and associated footnote as follows.
The SCPC units are being designed to burn an ~~un~~washed fuel.[70]

[70]DR-032 says coal washing will not occur at the ERGS site.

(p 109, Table 6-2) Comment: Please substituting the washed bituminous coal column from Table 9-1.

(p 110, par. 5) Clarification: Conveyors handling crushed coal will be installed inside enclosed galleries. Conveyors handling uncrushed coal would be covered conveyors.

(p114) **Solid waste production, storage, and beneficial use**
Comment: Please change quantities because of the updated bituminous coal characteristics (Washed Pittsburgh #8) as follows for the SCPC units:
165,200 tons per year of fly ash changes to 206,300 tons per year
38,600 tons per year of bottom ash changes to 51,600 tons per year
248,800 tons per year of gypsum changes to 543,600 tons per year

(p114, par. 3) **Water use, storage and discharge**
Comment: Delete first sentence and replace with the following: A new pump house will be installed on the southwest side of the proposed SCPC site plan. OCPP units 5-8 will utilize the existing south plant pump house that will withdraw water from the planned forebay area that will enclose the western end of the intake channel. Both the forebay and new SCPC pump house locations will be connected to the proposed intake tunnel by means of a vertical dropshaft.

(p116) **Fly ash**
Comment: Change "industrial" use to "commercial" use.

(p116) **Bottom ash**
Comment: Change "industrial" use to "commercial" use.

(p 116, par. 6) Plans for gypsum may also include conveyance to a wall board plant if one is constructed in nearby vicinity, or barging off site.

(p 122) HAPs, including mercury, would be controlled in the gasification process. Information from currently operating IGCC facilities suggests that at least 50 percent of the mercury is removed in this gasification process
Comment: We have committed to at least 90 percent mercury removal. This information is included in the revised air permit application.

(p 122, par. 4) Comment: typo. Consider revising as follows.

"The rated heat load input is estimated to be 5,035 million British thermal units (MMBTU/hr) as shown in Figure 6-9. The IGCC unit ~~heat rate~~efficiency would be 37 percent, which currently is slightly less than a SCPC unit under the same conditions."

(p126) **Solid waste generation and use**
Comment: Change quantities for the IGCC units based on more detailed information as follows:
18,000 tons per year of elemental sulfur changes to 33,200 tons per year
60,000 tons per year of sulfuric acid changes to 109,200 tons per year
Change 12,000 Btu/pound bituminous coal to 13,100 Btu/pound bituminous coal
Change 3.2 percent coal sulfur to 2.69 percent coal sulfur

(p 127) Interconnection on the plant site, 2nd paragraph. Suggest the following changes:
The interconnection would consist of three circuits. Two circuits from the plant area to the expanded 345 kV substation area and one circuit from the plant area to the 138 kV substation area. Each circuit would be approximately 4,000 feet in length. For the North Site, the line route from the generators to the substation would travel southwest over the coal handling area, then south to the new expanded 345 kV substation(see Figure Vol. 2-1). For the South Site ~~(see Figure Vol. 2-1)~~, the transmission interconnection lines from the SCPC units would head west northwest across the proposed rail loop track toward the expanded substation which would be located inside of the loop.

(p 128) Stability issues, 3rd paragraph. Suggest the following changes:
ATC issued a 10-Year Assessment Update February 2003. The update indicates the conceptual plan for a number of 345 kV lines in southern Wisconsin connecting to Illinois and Iowa. The Big Bend to Paddock 345 kV line is illustrated as one of several 345 kV lines that could meet future needs. The line is not being proposed at this time. With the recent removal of the interconnections for IC001 (Badger Gen – Kenosha~~Midwest Power – Germantown~~) and IC003 (Midwest Power – Germantown~~Badger Gen – Kenosha~~), a different stability solution may be available.

(p157, **Table 7-11, NO_x row, BACT column)** Comment: typo.
Low NOx burners and selective catalytic reduction

(p 181) Fall Turnover
"The annual temperature cycle can generally be broken down into three stages."
Comment: typo. This sentence is carried over from the previous paragraph, is redundant, and should be removed.

(p 193) Existing impingement and entrainment levels
"In 1985, units 1-4 were retired."
Comment: North Oak Creek Units 3&4 were retired in April 1988; Units 1&2 were retired in December 1989.

(p 194) Existing impingement and entrainment levels
"This system releases dissolved copper and aluminum into the intake water,….."

Comment: The Copper Ion Generator discharges into the House Service Water system that subsequently discharges to Lake Michigan via the condenser cooling water outfalls (WPDES outfalls 003, 004, 005 and 006).

(p200, par. 3) **IGCC unit**
Comment: typos – first sentence (p**o**wer block,…)

(p200, footnote) **IGCC unit**
Comment: typos – date reference should be 2-01-02 (not 2-10-02)

(p201, par. 3) **IGCC unit**
Comment: Flow rate in last sentence should be 2,948,900 gpm

(p201, par. 3) **Cumulative use** Comment: typos – IGCC (not OGCC) and 485,000 gpm (not gmp)

Comment: Delete first sentence of the final paragraph and replace it with the following: A new pump houses will be installed on the southwest side of the proposed SCPC site plan. OCPP units 5-8 will utilize the existing south plant pump house that will withdraw water from the planned forebay area that will enclose the western end of the intake channel. Both the forebay and new SCPC pump house locations will be connected to the proposed intake tunnel by means of a vertical dropshaft.

(p203, par. 3) **Description and location of proposed water intake system**
Comment: third sentence – delete the words "includes an on-shore pumping station". Also, for this paragraph the reference to a 3,500 feet intake can be deleted. Depth proposed for the intake cribs is about 43 feet.

(pp. 203-204) **Construction methods for the water intake transport system**
Comment: Delete the first paragraph of this section. Delete the first sentence of the first full paragraph on page 204. Alter the second sentence to state: "The proposed tunnel would be 32 feet in diameter and approximately 200 feet below the bed of the lake." Forth sentence – delete 30 foot reference. Fifth and sentences replace with – "The proposed design is to install four intake cribs at the lake bottom that will each connected to a 14 foot diameter tunnel that leads to a drop shaft that is 32 feet in diameter." Delete the sixth sentence.

(p 207) Comment: typo
ERGS ~~1,060,000~~10,600,000 tpy

(p 212) 1st paragraph
Comment: In discussing the dredging, it should be made clear that WE can already dredge a sizeable portion of the proposed navigational channel. This would be done as maintenance dredging of an existing channel.

Rooted Aquatic plants and algae (p218)
Lakebed surveys within the project area were undertaken in 2002 by the Great Lakes WATER Institute. Those studies show no aquatic macrophytes within the project area. Most of the project area is in water depths deeper than (typo) the maximum rooting depth of…

(p 225) Because the plant would use once-through cooling technology which returns water to Lake Michigan and the make-up water for the boilers would come from the municipal water supply, no water filtration or treatment would occur.
Comment: But in fact water treatment will occur, probably demineralization. In particular, the zero discharge facility for the IGCC unit will have a salt cake which will require disposal. At this time it is not known whether this will be a hazardous waste. Other wastes may be generated from the gasification process, including spent catalysts, carbon beds, and other assorted materials.

(p 229) **Early ash disposal areas** Comment: Typos
In addition to the two closed landfills and one open landfill, four early ash disposal areas (EADAs) were identified on the OCPP property. These are ~~five~~ four places on-site where OCPP ash was buried in the early years of plant operation.

Isolated Natural Resource Areas and ~~Primaray~~Primary ~~Environental~~Environmental Corridors are also described in Chapter 10.

(p 230) **Present methods of re-use** Comment: Please consider the following changes:
WEPCO's existing plant currently creates two main by-products: fly ash (class C and F) and bottom ash. Class C fly ash is produced by newer boilers and has more calcium. It is used as a cementitious material and is very good for making concrete. Class F fly ash comes from older boilers and has less or no calcium and a high carbon content. It has little to no economic value at this time.

At this time, over ~~90~~ 96 percent of these by-products are recycled. Class C fly ash is used as admixtures in concrete and soil stabilization beneath paved surfaces. Bottom ash is primarily used in construction, as sub-base below paved surfaces and beneath commercial buildings. Most of the high carbon Class F fly ash is utilized as a supplemental fuel at Pleasant Prairie Power Plant or utilized for manufacturing portland cement~~Most of Class F fly ash is landfilled~~.

(p230) **Fly ash and bottom ash** Comment: Please consider the following changes:
Table 9-1 illustrates the potential components of the ash by-products from the proposed ERGS SCPC units.

Based on the characteristics reported in Table 9-1, and an 85 percent capacity factor for the new SCPC units, WEPCO estimates that the amount of coal combustion by-products materials produced by each unit would be:

Fly ash ~~82,600 tons/year~~ 103,100 tons/year per unit
Bottom ash ~~19,300 tons/year~~ 25,800 tons/year per unit

Thus, a total of ~~165,200 tons per year of fly ash and 38,600 tons of bottom ash~~206,300 tons per year of fly ash and 61,600 tons of bottom ash would be produced each year by the two SCPC units. Using the standards in Wis. Admin. Code § NR 520.15 (20) and a field capacity conversion factor of 1.2 tons/cubic yard, the respective volumes of the fly ash and bottom ash would be calculated 171,899 cubic yards and 42,975~~at 137,666 cubic yards and 32,166~~ cubic yards. The total volume of fly ash and bottom ash together would be 214,874 ~~169,832~~ cubic yards per year.

(p231) **Synthetic gypsum** Comment: Please consider the following changes:

As discussed in Chapters 6 and 7, the ERGS SCPC units would utilize limestone or organic-acid promoted limestone to control and reduce SO2 emissions. The use of limestone versus organic-acid-promoted limestone would depend upon the fuel sulfur content. Synthetic gypsum by-product would be generated in this operation regardless. WEPCO estimates that about ~~124,400 tons/year~~ 271,800 tons/year per unit would be generated by each unit. The two proposed SCPC units would then create a total of ~~248,800 tons~~543,600 tons of gypsum per year.

(p232) **Elemental sulfur and sulfuric acid** Comment: Please consider the following changes:

In the sulfur recovery plant, the sulfur-containing gases from the Acid Gas Removal (AGR) system would be converted to either elemental sulfur or sulfuric acid. Elemental sulfur and sulfuric acid production would be directly related to the sulfur content of the coal. Based on the proposed fuel, the sulfur content of the coal would yield about ~~18,000 tons/year~~ 33,200 tons/year of elemental sulfur. The quantity of sulfuric acid produced would amount to approximately 60,000 tons/year, or 62,400 gallons per day. ~~This material may be considered hazardous waste.~~

(p 233) **Storage and Handling of Construction and Operation By-Products Fly ash**
Comment: Please consider the following change:
Fly ash collected in the fabric filter hoppers and the air heater hoppers **(**see Figures Vol. 2-1-to 2-**3)** would be conveyed to the fly ash storage silo via a pneumatic transport system using low-pressure air from a blower. The fly ash would be discharged through a wet or dry unloader and conveyed through a telescopic unloading chute into a truck for disposal or utilization.

(p233) **Bottom ash**
Comment: Please consider the following addition:
Bottom ash from the boiler would be collected and transported on a submerged scraper conveyor and dewatered. The ash would then be collected in a dump truck and hauled to a storage pad on site (see Figures Vol. 2-1 to 2-3**).** The ash collected on the storage pad could be loaded into a truck using a front-end loader. It could then be taken to a landfill or recycled as permit allows by NR 538 rules for beneficial utilization of industrial by-products.

(p233) **Gypsum**

par. 2 Comment: typo. Should say "Secondary dewatering….."

par. 3 WEPCO has not proposed the size of the storage shed at this time.
Comment: Please note that the storage shed is to be sized for 3 day storage (refer to air model).

par. 4 Comment: Please consider the following addition.
WEPCO must contract with commercial landfills for gypsum disposal until a wallboard plant is available to accept it or modify the license for the WEPCO landfills.

(p234) Elemental sulfur or sulfuric acid Comment: Please consider the following changes.
Either elemental sulfur or liquid sulfuric acid would be produced as part of the AGR process for the IGCC unit. WEPCO proposes an on-site, three-day storage for liquid sulfuric acid. Based on production of ~~62,400~~50,700 gallons of sulfuric acid per day; a bulk liquid storage of 200,000 gallons would be needed.

WEPCO has stated its intention to haul 30 truckloads (at 3,000 gallons per truckload) per day from the power plant on a Monday through Friday basis. Rail cars hold a capacity of 10,000 to 11,000 gallons and could be considered for longer distance shipments. This material may be classified as hazardous material. The storage and transportation will be regulated as a hazardous material like conventionally manufactured sulfuric acid~~waste. If determined to be hazardous waste, the storage and transportation will be regulated as hazardous waste~~.

(p 235) **Changes in hauling methods and timing** Comment: Please consider the following addition. WEPCO does not anticipate any substantial changes in the hauling methods or routes for solid waste from the new facilities. There would be an increase in truck traffic for transportation of ashes and other by-products from the ERGS to other WEPCO-owned landfills if the Caledonia landfill capacity is exhausted.

(p236) **Disposal in local landfills** Comment: Please consider the following changes.
As discussed at the beginning of this chapter, WEPCO operates three licensed landfills in the southeast region. The three active landfills are not near capacity and are expected to remain operational for many years. As noted above, the SCPC units are expected to generate ~~165,200 tons/year (82,600 tons per unit per year)~~257800 tons/year (128,900 tons per unit per year).

(p236) **Need for changes in landfill operating plans or licenses** Comment: Please consider the following change.
WEPCO is required to submit plan modifications to the DNR for any of the landfills they plan to use for disposal of newly generated by-products. WEPCO ~~would~~ may also be required to update the design of these landfills to provide better protection for the groundwater.

(p237) **Oak Creek North (OCN)** Comment: Please consider the following change.
Phase II -- Fill would be placed and temporary parking facilities would be constructed. These actions would also result in changes in surface drainage off of the landfill. See the discussion in Chapter 8 on stormwater discharge. The landfill reconfiguration will improve cover impermeability, drainage characteristics and minimize the production of leachate. Long term plans for the OCN site include source removal for use as a supplemental fuel in the proposed generating units. The site will eventually be reclaimed and become available for other uses.

(p237) **Oak Creek South (OCS)** Comment: Please consider the following correction.

Coal combustion by-products generated by the OCPP were disposed of at the OCS beginning in 1974 when it was licensed until it reached its capacity in May 1992 and was covered. The OCS landfill covers 80 acres and contains 3,760,000 cubic yards of ash.

(p237) Comment: Please consider adding an additional bullet.
As discussed in Chapters 10 and 11, construction of the ERGS would require excavation of a significant amount of native soil for construction of the new power plant units and other features. The proposed modifications to the OCS landfill involve:
• Placement of soil on the top. Fill would be placed at a minimum thickness of eight feet over the cover of the OCS.

• Compaction and grading of the newly placed soil to prepare a construction laydown area. Following the relocation of soil, predominantly clay in composition, from the ERGS excavation areas to the top of the OCS, a construction laydown area would be placed as the final surface.
• Construction of access roads and development of short- and long-term stormwater management facilities.
• Proposed cover upgrades from the ERGS project will reduce the production of leachate at the OCS landfill.

(p237) **Beneficial Re-use Ash** Comment: Please consider the following correction.
WEPCO has a beneficial ash re-use program in place. Companies have been working with WEPCO since 1980 to market fly ash and bottom ash from WEPCO's existing coal-fired plants. Since 1980, re-use of the ash has increased until about ~~90~~96 percent of the by-products from its power plants are now beneficially used.

(p 237) Comment: Please consider the following addition.
Bottom ash is now being utilized as base or sub-base material for building floors and foundations, paved roads, and parking lots. Fly ash is now being utilized in cements as a raw feed material for portland cement production, soil stabilization, cold in-place recycling of asphalt pavements, in controlled low-strength materials, and as a supplemental fuel.

(p 237) Comment: Please consider the following change.
WEPCO has approached marketers for their projections on reaching full utilization of the fly ash and bottom ash and has received optimistic replies (these are filed at the PSC as part of WEPCO's CPCN application.) A.W. Oakes & Son of Racine, Wisconsin has indicated that it could utilize 100 percent of the bottom ash within two years of the commissioning of each unit. Mineral Solutions, Incorporated has indicated that it could utilize 100 percent of the fly ash within three years of the commissioning of each unit. This would require working to expand the market for Class F fly ash. Class F fly ash can be used to produce high performance concrete if it meets ASTM C-618 and has consistent quality from a base loaded power plant. WEPCO's current sources of Class F fly ash have high carbon content and thus are not suitable for use in concrete.~~Class F fly ash is not a good ash for making concrete because it contains less than 10 percent calcium oxide (CaO). However, if water is added to it, it somewhat hydrates and solidifies. It has been marketable as "controlled low strength material" (CLSM) or as "flowable fill" (concrete that flows). Basically, it can make a weak concrete for nonstructural use. For instance, it has been used for abandonment of utility tunnels. This market is very limited.~~

(p239) **Table 9-2** Comment: Table 9.2 below is an update to reflect Pittsburgh #8 washed bituminous coal and shows quantities of coal combustion products projected for storage at the Caledonia landfill based on the 10 year straight line utilization growth assumption.

Table 9-2 WEPCO's Projected Annual Coal Combustion Products Landfill Quantities for Fly Ash, Bottom Ash, and Slag

Year	SCPC FA	SCPC BA	SCPC FA	SCPC BA	IGCC Slag	Total
2007	103,100	25,800	0	0	0	128,900
2008	92,790	23,220	0	0	0	116,010
2009	82,480	20,640	103,100	25,800	0	232,020
2010	72,170	18,060	92,790	23,220	0	206,240

2011	61,860	15,480	82,460	20,640	100,000	280,460
2012	51,550	12,900	72,170	18,060	90,000	244,680
2013	41,240	10,320	61,860	15,480	80,000	208,900
2014	30,930	7,740	51,550	12,900	70,000	173,120
2015	20,620	5,160	41,240	10,320	60,000	137,340
2016	10,310	2,580	30,930	7,740	50,000	101,560
2017	0	0	20,620	5,160	40,000	65,780
2018	0	0	10,310	2,580	30,000	42,860
2019	0	0	0	0	20,000	20,000
2020	0	0	0	0	10,000	10,000
2021	0	0	0	0	0	0
TOTAL	567,050	141,900	567,050	141,900	550,000	1,967,870

(p 260) In summary, the topography of the present OCPP property would be altered with a large amount of soil excavation, transport, and deposition to accommodate the two SCPC units at the lakeshore for once-through cooling access and the IGCC combined-cycle and AGR units to handle their water needs as well.
Comment: AGR should be ASU (Air Separation Unit).

(p 275) 2nd par.
Comment: The OCPP currently has two stacks.

(p 277) Communities close to the power plant site
Comment: typo
Communities closest to the site may experience increased noise, dust, traffic problems, and visual impacts. Communities more than one-half mile away are usually too far from a power plant site to experience most of these impacts, but there exceptions, especially with respect ~~top~~ to visual impacts along the lakeshore.

(p 279) **Table 11-1**.
Comment: The column labeled in operation appears to have the wrong dates for OC U-2 & 3 (others are close). The following information was obtained from NERC.

Unit Name	Commercial Operation Date
Oak Creek 1	9/30/1953
Oak Creek 2	10/21/1954
Oak Creek 3	12/3/1955
Oak Creek 4	10/22/1957
Oak Creek 5	12/31/1959
Oak Creek 6	11/25/1961
Oak Creek 7	3/16/1965
Oak Creek 8	10/31/1967
Oak Creek 9	2/10/1969

(p 299) **Jobs and Employment**

Expected changes in on-site employment

During construction (temporary)

Comment: typo

The electric utility industry has one of the lowest workers per dollar investment ratio. SCPC Units 1 and 2 would each take four years to construct using an average work force of 500 employees for each unit. The maximum number of employees ~~world~~ would be 600 people per unit….

(p306) Causes of increased traffic

Comment: Please consider the following correction.

The sources of increased traffic during construction are: (1) truck delivery of equipment and supplies, (2) additional employee vehicles, and (3) possible hauling of soil offsite by truck. Increased traffic during operation could be due to: (1) truck delivery of supplies, (2) additional employee vehicles, (3) vehicles used in routine maintenance, (4) ash shipment to market, (5) vehicles needed for mining of landfill ash, and disposal of byproducts, and (6) gypsum shipments to market if there is not a wallboard plant onsite or if not barged off site.

(p 309) Ash shipments Comment: Please consider the following clarification.

The number of vehicle trips for shipment of ash to off-site beneficial-use markets or waste disposal sites is not included in Table 11-14. At first, the applicants plan to store ash at the on-site Caledonia Landfill. Off-site ash shipments would start ~~only after all three units are operational,~~following startup of the first unit, ramping up to 100 percent utilization ~~and~~ after markets for the ash are fully developed. Table 11-15 shows the ultimate amount of off-site ash shipment, although shipments are likely to start at a lower number and increase as markets develop.

(p 330) Proposed changes to lands adjacent to Haas Park Comment: Please consider the following correction (typo).

The existing power plant chimneys are currently visible from Haas Park. Three new stacks or chimneys would be added if the entire ERGS facility is built. The new stacks for the SCPC units ~~and the IGCC~~ would be higher and larger in diameter than the OCPP stacks. Refer to the Visual Impacts section of this chapter for more information.

(p 330) **Table 11-15** Comment: typo in footnote **

(p 339) **Figure 11-14** Comment: Please consider revising the Figure title for accuracy as follows.

New residential area near existing ~~T~~transmission lines ~~passing through new residential areas~~

(p335) Shore access and fishing

Concerns about the effect of the ERGS facility on local fish populations are addressed in Chapter 8. Based on interested generated by the public, the applicants have developed some initial ideas for fishing access on the north end of the property as close to the proposed warm water discharge (for the North Site) as possible. They have also sponsored meeting with ~~lcoal~~local (typo) fishing groups to get feedback.

(p 349) Splitting coal delivery between rail and ship options
Table 11-29 'Average number of trains per week entering the Oak Creek/ERGS site under a range of coal delivery options (compared to a current five trains of 125 cars per week)

(p 350) Process for altering railroads and ownership
"WE Power would also pay for any other changes to town or country roads due to the proposed power project."
Comment: "Any" is too broad. Suggest using the word "specific" instead.

(p 352) Comment: Please consider the following clarification to the 6th bullet for accuracy.
The summary included the following:
• 30 coal trains passed Four Mile Road traveling to and from the Oak Creek site
• The number of vehicles stopped at the crossing (for coal trains) averaged 24, with a maximum of over 50
• Coal train crossing times averaged 3 minutes 48 seconds
• The maximum coal train crossing time was 8 minutes 50 seconds
• The minimum coal train crossing time was 2 minutes 17 seconds
• There were 61 other (non-coal) trains or gate closings

(p361) Wetlands Comment: typo
An overpass (rather than an underpass as proposed) at Six Mile Road, would have greater land disturbance and wetland impacts than other alternatives. It would also be more expensive than the ~~Benisch~~ Benesch recommendation

(p 365) Table 11-38, footnote 2. Comment: I-93 should be I-43.

(p 365) Effect of a proposed new 4-mile transmission line Comment: Please consider the following clarification.
The proposed new transmission line is a 345 kV line that would extend from the substation on the OCPP/ERGS site to the Chicago and Northwest (C&NW) railroad track (It is listed as reinforcement 2a on Table 6-4). This new line would be one transmission circuit, (a set of three ~~lines~~conductors) with three insulator strings. Some transmission structures carry two circuits (six ~~lines~~conductors) on two sets of arms. At the C&NW railroad track, the circuit from this new line would continue on existing, two-circuit structures which are only carrying one operating circuit now.

Chapter 7 - Air Emissions

This chapter has three primary components. The first section is a general description of the pollutants produced by coal-fired power plants and an explanation of the general concerns related to these pollutants. The next section of the chapter is quite technical. It includes a description of the DNR permitting process, the existing air quality in the region, the projected emissions of the proposed generating units, and the emission control technologies likely to be required by the air construction permit, if granted by the DNR.

The last section of the chapter contains the results of WEPCO's air modeling analysis and the expected air quality impacts of constructing and operating the proposed ERGS project. The tables in this section (Tables 6-23 through 6-30~~28~~) show how the calculated actual emissions (which assume that the best available control technologies have been implemented), in combination with the background air pollutant concentrations, compare to the national ambient air quality standards (NAAQS) and the Prevention of Significant Deterioration (PSD) increments. As stated frequently throughout this chapter, the DNR must still conduct its own air quality modeling analysis in order to determine if the project is permittable, and if so, under what circumstances and conditions.

It is expected that DNR's air modeling analysis will be mostly completed by the time that the final EIS is issued. ~~. Proposed changes in the height of the exhaust stacks for the two SCPC units if located on the South Site or the South Site-Exp option have only recently been submitted to the DNR.~~ Testimony related to the completed analysis will be provided by the DNR at the time of the project hearings. Finally, several short summary points are found at the conclusion of the chapter, to highlight some of the key areas of information in the chapter.

Common Pollutants of Coal-burning Power Plants (p. 133)

The combustion of fossil fuels by coal-burning power plants can create harmful impacts to the environment and to human health. Some of the toxic chemicals that are emitted from power plants include a variety of metals, organic compounds, acid gases, sulfur, nitrogen, carbon dioxide, and particulate matter. The quantity and type of emissions from coal combustion greatly depends on the rank and composition of the fuel, handling of the fuel, the type and size of the boiler, firing conditions, types of emission control technologies, and the level of equipment maintenance.

Currently, power plants account for 73 percent of Wisconsin's sulfur dioxide (SO_2) emissions and ~~nationally, 27~~ (please provide percentage based on WI NOx emission totals) percent of the nitrogen oxide (NOx) emissions. Once released into the air, some of these chemicals react in the atmosphere and can form particulates, increase ozone levels, reduce visibility (smog), and acidify surface waters. They (~~are a major contributor of greenhouse gases and~~ SOx and NOx are not major GHG contributions; however, CO2 and methane are. We suggest a new sentence at the end of this Paragraph) can also cause significant health problems especially for the elderly, individuals with heart and lung disease, and children. In addition, fossil fuel-based power plants emit large quantities of CO_2, which is a major component of a group of gaseous compounds known collectively as Greenhouse Gases.

State and federal regulation imposes limits on many of the emitted pollutants to protect human health. The EPA's National Ambient Air Quality Standards (NAAQS) regulate the emissions of six "criteria" pollutants: carbon monoxide (CO), nitrogen dioxide (NO_2), ozone (O_3), lead (Pb), particulates (PM_{10} and $PM_{2.5}$), and sulfur dioxide (SO_2). State air permits also regulate the emissions of these and other classes of pollutants. Regardless of whether areas and emission sources within these areas ~~the facility~~ meet~~s~~ existing standards, there is often a question of whether sensitive individuals are adequately protected. In general, when air pollution levels increase, sensitive individuals may experience adverse respiratory symptoms. The problem is complicated because some of the harmful pollutants emitted by coal-burning power plants such as NO_x are also emitted in ~~a~~ larger amounts ~~percentage~~ by motor vehicles and some of the pollutants travel long distances from their source.

Particulates (p. 134)

Particulate matter (PM) is a complex mixture of very tiny solid or liquid particles, composed of chemicals, soot, and dust. Their chemical and physical composition varies widely because particulates originate from a variety of sources. Coarse particles (10 to 2.5 micrometers in diameter) arise mostly from wind blown dust and unpaved roads. Very fine particles (less than 2.5 micrometers in diameter) are formed ~~caused~~ by the reaction in the atmosphere of emitted organic gases, NO_x, sulfur oxides (SO_x), and ammonia. Power plants and motor vehicles are the primary sources of NO_x emissions that react ~~oxidize~~ in the atmosphere and form PM. The primary source of SO_2 emissions are power plants and other fossil fuel ~~coal~~ combustion sources, including mobile sources, ~~burning facilities~~ which react in the atmosphere to form sulfate particles. These very fine particles can remain suspended in the air for long periods of time and travel 10 to 100 miles before deposition occurs. In addition, mobile sources, but especially diesel-fueled vehicles, appear to be the major sources of organic compounds that comprise 30-40% of fine PM, especially in urban areas.

Both sizes of particles can penetrate into the sensitive respiratory tract. As inferred by several epidemiological studies, ~~F~~fine particles are linked to the most serious health effects: aggravate asthma, emphysema, chronic bronchitis, increase coughing, decreased lung function and can contribute to an early death. While several epidemiological studies have shown a statistical relationship between fine PM and adverse health outcomes, health scientists have yet to understand what the causal mechanisms may be or what components of fine PM maybe linked to the adverse effects. Exacerbations of asthmatic conditions often appear to be the result of increases in PM in the local atmosphere.

The sulfate component of PM has been implicated in the ~~many negative impacts including,~~ corrosion of metals, damaging and staining of stone buildings and monuments, soiling of structures and motor vehicles, and harmful impacts to vegetation and the environment.

PM has the potential to cause haze and affect local and regional visibility. Haze is caused when sunlight encounters tiny pollution particles in the air. As the amount of PM increases, more light is scattered and absorbed, which reduces the clarity and color of what is seen. Periods of poor visibility normally occur in conjunction with elevated levels of PM and ozone.

The EPA has set standards for particulate matter with a diameter of 10 micrometers or less (PM10). All of Wisconsin meets the current PM10 standard. In 1997, the EPA adopted a new standard for fine particulate matter with diameters of 2.5 microns or less (PM2.5). This was in response to studies which show greater health concerns surrounding low concentrations of fine PM because it has the potential to penetrate deeper into lungs. Implementation of the PM2.5 standard was challenged in court but was upheld by the Supreme Court in 2001. The EPA plans to establish non-attainment areas (areas that do not meet the PM2.5 standard) and then take steps to reduce its emissions. Wisconsin's PM2.5 monitoring network has been operating statewide since 1999. **Through 2002, no violations of EPA's $PM_{2.5}$ standard have been detected in Wisconsin.**

NOx (p. 135)

NOx is the generic term for a group of highly reactive gases, all of which contain nitrogen and oxygen in varying amounts. The primary sources of NOx emissions are motor vehicles (40 percent) and electric utilities (40 percent). The primary NOx emission from the combustion of coal is nitric oxide (NO), with only a few volume percent as nitrogen dioxide (NO_2), and a few parts per million (ppm) of nitrous oxide (N_2O).

NOx is one of the main ingredients in the formation of ground-level ozone (see ozone section). One form of NOx, nitrous oxide (N2O), is a greenhouse gas and contributes to global warming (see greenhouse gas section). Nitrogen oxides can also form small nitrate particles that are associated with serious health impacts like heart attacks. Additionally, the nitrate particles can form nitric acids in the atmosphere which contributes to acid rain, and can, under the right water chemistry conditions, result in ecosystem eutrophication, since certain nitrogen compounds are very effective soil fertilizers.
~~provide too much nitrogen and over-fertilizing the ecosystem.~~
High levels of NO2 may be fatal to humans, while lower levels affect the delicate structure of lung tissue. Humans exposed to high concentrations suffer lung irritation and potential lung damage. Long-term lower levels of exposures can destroy lung tissue, leading to emphysema. Concentrations of NOx as low as 0.1 ppm, can cause lung irritation and measurable decreases in lung function in asthmatics. Children, the elderly and people with lung diseases, such as asthma, emphysema or bronchitis are sensitive to NOx.

Since 1970, EPA has tracked NOx emissions. To help reduce acid rain, EPA devised a two-phased strategy to cut NOx emissions from coal-fired power plants. In Phase I of the strategy (1995~~6~~-1999), NOx emissions were reduced by over 400,000 tons per year by installing burner and air supply equipment that stage delivery of oxygen to burning coal in utility power plants. The goal of the second phase is to reduce emissions by over 2 million tons per year beginning in the year 2000. NOx emissions increased 9 percent between 1982 and 2001 and decreased 3 percent between 1992 and 2001. Concentrations of nitrogen dioxide (NO2) in the air decreased 13 percent between 1982 and 1992 and by 11 percent between 1992 and 2001.

SO2 (p. 135)

Sulfur is a component of both coal and crude oil, including some of the refined products of crude oil such as gasoline and diesel fuel. . Gaseous sulfur oxides are emitted when the sulfur is oxidized during the combustion process. On average, about 95 percent of the sulfur present in bituminous coal would be emitted as gaseous sulfur oxides, primarily SO2. The amount of SO2 released into the atmosphere through the exhaust stack would depend on the sulfur content of the coal. Nationwide, the sulfur content of coal normally ranges between 0.7 and 2 percent by weight. However, much of the coal mined in the eastern U.S. has a much higher sulfur content. The SO2 emissions from Wisconsin coal-burning power plants currently accounts for 73 percent of all sulfur oxide emissions in the state. These SO2 emissions and sulfate particles are often transported long distances and deposited far from the point of origin.

Sulfur dioxide, at levels in excess of the ambient standard, causes a wide variety of health and environmental impacts because of the way it reacts with other substances in the air. SO2 irritates the respiratory system and can cause pronounced health problems. Sulfate particulates are a primary factor in the production of hazy atmospheric conditions. Acid rain is caused by SO2 and NOx reacting with other substances in the air (see Acid Rain section). Corrosion and damage to metals and masonry may also result from increased sulfur dioxide emissions.

Severe health affects are associated with increased sulfur dioxide emissions. Peak levels of SO2 in the air can cause breathing difficulty for people with asthma. Long-term exposure to high levels of SO2 gas and particles may cause respiratory illness and aggravate existing heart disease. Sulfate particles are associated with increased respiratory symptoms, respiratory disease, and premature death. Exposure to high concentrations of sulfur dioxide for short periods of time can constrict the bronchi and increase mucous flow, making breathing difficult. Children, the elderly, those with chronic lung disease, and asthmatics are especially susceptible to these effects.

Acid rain (p. 136)

Acid rain has been studied in Wisconsin since the early 1980s. The combustion of fossil fuels is the major cause of acid rain. Rain uncontaminated by any pollutants has a pH of 5.0 to 6.0. Rain with a pH less than 5.0 is considered "acid rain". The primary cause of acid rain is the emissions of SO2 and NOx, which enter the atmosphere and combine with moisture, returning to earth in the form of acidic rain, snow, or fog. Acidic deposition also may occur in a dry form when acidic compounds attach to particulates and return to earth. These acids can overwhelm the neutralizing capacity of some soils and lake waters.

Research has determined that acid rain is linked to declines observed in the health of many forests in the U.S. However, there has been no identified major decline in Wisconsin forests due to acid rain. Bodies of water affected by acid rain lose some of their biodiversity as more acid-sensitive species of plant and animal life die off or experienced a decrease in reproductive success. Approximately 2 percent of Wisconsin's lakes are acidic and an additional 10 percent are "extremely" sensitive to acid rain. Acid deposition also has been connected to elevated mercury concentrations in fish and fish-eating wildlife. This in turn endangers the health of people, especially infants and children who may eat fish from affected lakes.

In 1986, Wisconsin passed one of the first and strongest state acid rain control laws in the nation. Wisconsin's major electric utility companies were required by 1993 to reduce their SO2 emissions by 50 percent from 1980 emission levels. In 1990, overall annual SO2 emissions from electric utility companies had fallen 46 percent. In 1990, the Clean Air Act Amendments were enacted, requiring electric utility companies nationwide to reduce their collective SO2 emissions by the year 2000 to 10 million tons per year below 1980 emission levels (or 40 percent). Utility SO2 emissions will be capped at 8.9 million tons per year in the year 2000 and thereafter.

Results of these and additional regulations have increased ~~reduced~~ the average pH levels (reduced the acidity) of the state's rain. In 1990, the annual average pH ranged from 4.59 in southeastern Wisconsin to 5.06 in northwestern Wisconsin. In the early 1980s, pH levels ranged from 4.4 to 4.8. For the last several years, the streams and lakes in the northeastern and upper Midwestern parts of the U.S. have shown decreased sulfate concentrations and increased pH levels, indicating a consistent improvement. In the upper Midwest, the number of acidified lakes has gone from 3 percent to less than 1 percent.

Greenhouse gases (p. 137)

Fossil fuel consumption is the major source of greenhouse gas emissions in Wisconsin. Greenhouse gases include carbon dioxide (CO2), methane (CH4), and nitrous oxide (N2O). Automobiles and electric utility power plants add to the levels of these naturally-occurring gases. Since the beginning of the industrial revolution, atmospheric concentrations of CO2 have increased nearly 30 percent, CH4 concentrations have more than doubled, and N2O concentrations have risen by about 15 percent. These increases have enhanced the heat-trapping capability, or "greenhouse effect" of the earth's atmosphere.

Electric utilities are responsible for 33 percent of Wisconsin's greenhouse gas emissions. Nearly all of the fuel carbon (99 percent) in coal is converted to CO2 during the combustion process. Green house gas emissions may increase many health and environmental impacts. However, to what extent, in what part of the world, and in what time frame these impacts may occur are current items of intense scientific debate. The federal government has adopted a goal of reducing greenhouse gas emissions in the U.S. to 1990 levels. For Wisconsin to reduce emissions in 2010 to its 1990 level, annual greenhouse gas emissions would have to be reduced by about 37 million tons from the currently projected 2010 emissions.

Ozone and Volatile Organic Compounds (p. 137)

Ground-level Ozone (O3), a principal component of smog, is created when ~~cars~~motor vehicles, power plants, large
factories, ~~mobile~~ and other sources emit volatile organic compounds (VOCs) and NOx which interact with sunlight. Ozone levels rise most frequently during the summer months.

In general, as ground-level ozone concentrations increase, more and more people experience health effects and the effects become more serious. Exposure to ozone in excess of the Federal NAAQS standards can trigger health problems such as chest pain, coughing and lung damage, and aggravate conditions like asthma, bronchitis, heart disease, and emphysema. Ozone irritates the respiratory system. Exposure to ozone may reduce the ability of the immune system to fight off bacterial infections. Those most likely to be affected by ozone exposure include active children and adults, people with asthma, and people that are unusually sensitive to ozone. Frequent exposure can cause permanent lung damage.

Ozone can also damage crops, trees, rubber, fabrics, and other materials. Ozone impairs the ability of plants to produce and store food. This reduces the yield and weakens the plants' ability to survive disease, insect attacks, and extreme weather like drought or wind. Ozone can have long-term effects on forests and ecosystems.

Ozone is regulated under the EPA's National Ambient Air Quality Standards (NAAQS). Counties that do not meet the ozone standard are designated as either, marginal, moderate, serious, severe, or extreme "non-attainment" areas. Six Wisconsin counties (Kenosha, Milwaukee, Ozaukee, Racine, Washington, and Waukesha) are designated as being in severe non-attainment of the national one-hour ozone standard. ~~Manitowoc County is designated as moderate non-attainment and~~ Door County is designated as a marginal rural transport non-attainment. The DNR has requested EPA to the change the status of ~~Manitowoc and~~ Door counties to attainment based on air quality monitoring data.

In addition to the one-hour ozone standard, in 1997 the EPA adopted an eight-hour ozone standard. Monitoring data has indicated that ten Wisconsin counties may be non-attainment for the eight-hour ozone standard. They include, in addition to the six one-hour ozone non-attainment counties, Door, Kewaunee, Manitowoc, and Sheboygan. U.S. Environmental Protection Agency (EPA) will make final eight hour non-attainment designations by April 15, 2004.

States are required to use specific control measures to achieve compliance with the NAAQS including the development and adoption of a State Implementation Plan (SIP). The SIP identifies the measures a state is taking to control emissions of regulated pollutants and how these measures will meet the standards by specified deadlines. The EPA required Wisconsin to submit a SIP that would result in a 15 percent reduction of ozone-forming VOCs from a 1990 base level of emissions. And, starting in 1996, the state was required to achieve an additional 3 percent annual reduction in VOCs in the severe non-attainment counties. Wisconsin ~~must~~ has to demonstrate to the EPA that the targeted reduction in emissions was achieved in 1996 and every third year thereafter until the area reaches attainment or until the required attainment date in 2007. Using various emission-controls and programs, Wisconsin has met all rate-of-progress requirements and emission-reduction milestones.

Stationary air pollution sources are regulated through the Wisconsin's air permit program. Existing stationary sources in non-attainment areas are required to install equipment with emission controls. The facilities that must install control equipment are determined based on the amount of pollution emitted by the facility, the severity of the pollution problem in the non-attainment area, and the industrial category of the facility. The emission limits are referred to as reasonably available control technology (RACT).

Hazardous Air Pollutants (HAPs) (p. 138)

Hazardous air pollutants emitted from coal-fired utility boilers and IGCCs may be classified in four broad categories:

a. Inorganic, solid phase HAPs, such as arsenic
b. Inorganic, acid gas HAPs, such as hydrochloric acid
c. Organic HAPs, such as formaldehyde
d. Mercury

Inorganic, solid HAPs occur as trace substances in coal. These substances are emitted by power plants in solid form, and are ~~generally~~ effectively controlled by modern, high- efficiency particulate matter control devices such as electrostatic precipitators and fabric filter baghouse. Inorganic, acid-gas HAPs include primarily hydrochloric acid and hydrofluoric acid, formed from trace substances in the coal. Flue gas desulfurization (FGD) systems which are primary used to control SO2 emissions reduce flue gas temperatures may condense and improve the control of these substances. In addition these acids are generally highly water soluble and are effectively controlled in wet FGD systems. Regardless of the emission control technology used, power plant organic HAP emissions are best controlled through good combustion practices.

Mercury chemistry and its control is complex. It is discussed in the next section on its own.

Mercury (p. 138)

Currently, 341 Wisconsin lakes and river stretches carry fish consumption advisories for mercury (Hg). The DNR estimates that Wisconsin sources of Hg contribute as much as 50 percent of the Hg entering Wisconsin lakes. However, recent transport and fate modeling by EPRI strongly suggests that the actual contribution of utility mercury emissions to mercury deposition in Wisconsin is likely to be much less than 10%. The rest comes from sources in other states and countries, and some comes from mercury-contaminated sediments already in the lake and river bottoms. Hg is a naturally-occurring element that is found in soil, wood, and petroleum. Because Hg is an element, human activities such as the combustion of fossil fuels do not create Hg. Rather, these activities liberate ~~transfer~~ Hg from the limestone or fossil fuels into the air.

Airborne Hg falls back to earth in precipitation, ending up in lakes. Bacteria in lake sediment convert inorganic Hg into methylmercury, which is ~~a form~~ easily absorbed by fish and other organisms, including people who eat these fish. Studies have shown that Hg accumulation in fish-consuming wildlife may lead to reproductive problems ~~.~~ **in certain wildlife species, such as the common loon** .Human consumption of fish that contain large amounts of methylmercury ~~Hg~~ can damage the nervous system, especially in children and fetuses.

To reduce Hg entering Wisconsin's environment, the DNR is proposing new rules lowering the amount of Hg emitted by coal-burning power plants and other major emitters. Wisconsin sources emitted about 6,580 pounds of Hg to the atmosphere in 1995, with about half of those emissions coming from energy production. A detailed estimate of the Hg sources is summarized in Table 7-1.

Table 7-1 Estimated mercury air emissions in Wisconsin in 1990 and 1995*

Activity	1990	1995
Energy Production		
Coal (total)	(2,361)	(2,508)
Coal (electric utility)	1,967	2,088
Coal (industrial and residential)	394	420
Petroleum sector	580	509
Wood	13	10
Natural gas	0.24	0.3
Refuse and tire-derived fuel	17	21
Gasoline and diesel - mobile	223	231
Subtotal	3,188	3,268
Purposeful Use of Mercury		
Latex paint volatilization	500	10
Municipal solid waste combustion	1,041	176
On-site household waste incineration	666	270
Medical waste combustion	363	601
Sewage sludge incineration	166	166
Fluorescent lamp breakage	107	107
Chlor-alkali production	1,072	1,114
Volatilization during solid waste collection and processing	258	258
Miscellaneous	128	127
Subtotal	4,774	3,168
Emissions Incidental to Other Activities		
Pulp and paper manufacturing	4	4
Soil roasting	12	12
Lime production	92	128
Subtotal	108	144
Grand Total - All Hg Sources	8,069	6,580

*Source: Bureau of Air Management, Wisconsin Department of Natural Resources.

Hg emissions from coal combustion can be controlled through pre-combustion controls, such as fuel cleaning, or through existing post-combustion controls. Post-combustion controls can include particulate control systems such as electrostatic precipitators (ESPs) or fabric filter baghouses, fluegas desulfurization (FGD) systems, and the injection of sorbents such as activated carbon. Table 7-2 provides a much simplified summary of EPA's current knowledge on the control of mercury emissions from coal-fired utility boilers. EPA obtained these data from mercury testing that was implemented according to EPA's mercury Information Collection Request (ICR). Note that the reduction levels listed in Table 7-2 are based on a very limited set of test data. Tests were done over a single 10-hour period in 1999, and therefore the results are not representative of fuel and operating variability which occur under normal operating conditions. In addition, the ICR confirmed that coal type, pollution control equipment, and other parameters have a significant impact on the magnitude of mercury removal.

Table 7-2 Average mercury emission reductions for various control devices

Boiler Type	Control Device	Control Efficiency	
		Bituminous Coal	Subbituminous Coal
Pulverized coal	Cold Side ESP	46%	16%
Pulverized coal	Hot Side ESP	12%	13%
Pulverized coal	FF Baghouse	83%	72%
Pulverized coal	Dry FGD Scrubber and FF Baghouse	98%	25%
Fluidized bed boiler	FF Baghouse	90%	No Test

Mercury-specific post-combustion controls for mercury such as activated carbon sorbent injection systems are currently in the research and development stage. The U.S. DOE, in collaboration with EPA and EPRI has funded limited testing of sorbent injection at four coal-fired power plants, including We Energies Pleasant Prairie Power Plant. The trial tests were generally limited to one week of continuous injection of activated carbon. Prior to the trial tests, a series of limited tests were performed with other sorbents to identify the most effective sorbents to use in the subsequent longer term trials. For Pleasant Prairie, the study concluded that the maximum mercury removal rate achievable was 60-70%. However, the injection of any amount of activated carbon rendered the flyash unsuitable for resale as an ingredient in readi-mix concrete (We Energies currently sells all of the flyash produced by this plant). Activated carbon sorbent injection systems are not yet commercially available, but continue to undergo refinement and full-scale demonstration at selected power plants, including at We Energies Presque Isle Power Plant in Marquette, Michigan.

During combustion, Hg in the coal and limestone is volatilized and may remain in a volatile or gaseous state throughout the boiler and pollution control systems. As long as the Hg remains in a volatile state, it cannot be collected by particulate control devices. Typical flue gas temperatures for conventional coal-fired boilers in Wisconsin are approximately 300 o F for cold-side electrostatic precipitators (ESPs), and approximately 700 o F for hot-side ESPs. The use of FGD systems significantly reduces flue gas temperatures, providing the opportunity to condense and collect the Hg compounds[73].

The EPA estimates that the current air pollution control devices installed on utility coal-fired units capture an average of 43 percent of the Hg in the coals combusted in the United States. Based on the current state of knowledge, the average emission control efficiency in Wisconsin

may be less than this national average because most of Wisconsin's power plants burn Subbituminous coals, which do not require sulfur removal to meet existing Federal SO2 emission standards.74
In addition, as concluded by DOE, EPA, and EPRI, the form of Hg released by burning sub-bituminous coal (principally elemental mercury), is not water soluble nor does it readily adhere to fly ash particles that are produced by this coal. Studies have also demonstrated that wet flue gas desulfurization devices do not remove elemental Hg.

Conversely, eastern bituminous coal-fired utility boilers ~~combustion~~ controlled by fabric filter baghouses (the technology proposed for the ERGS SCPC units) may achieve,~~s~~ based on short term ICR test results, 83 to 98 percent reduction in Hg. Therefore, the use of this technology could represent a 70 to 90-plus percent reduction in the current mercury emission rates from coal combustion in Wisconsin [not true for units that burn PRB-85% coal burned in Wisconsin is PRB]. Furthermore, the EPA states that dry FGD systems are already equipped to control emissions of SO2 and PM. The modification of these units by the use of appropriate sorbents for the capture of Hg and other air toxics is considered to be a solvable retrofit. In other words, the controls proposed for the ERGS SCPC units also have an improved potential for mercury control through sorbent injection. However, the ERGS SCPC units will utilize a wet FGD. Dry FGD system produce a product that must be landfilled rather than having a commercial value.

In May 2000, the DNR received a petition to adopt rules requiring reductions in Hg emissions to the air. The petition was signed by a number of legislators, environmental organizations, conservation groups, and sports clubs. In its December Board meeting, the Natural Resources Board instructed

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73 A fluegas FGD system is proposed to be installed on the two SCPC units.

74 Bituminous coal is WEPCO's fuel of choice for all three units of the ERGS project.

the DNR to begin drafting rules to reduce mercury emissions in Wisconsin. The Board instructed DNR staff to prepare proposed rules for the March 2001 Board meeting that protect public health and the environment but are cost effective, and reasonable and do not interfere with the utilities' ability to supply the state's energy needs.

In a separate regulatory initiative, the EPA announced on December 14, 2000, that it would require reductions of Hg emissions from coal-fired power plants. The agency planned to propose regulations by 2003 and issue final rules by 2004. Under the Clean Air Act, the EPA had been required to study toxic air pollution from power plants in order to determine if additional regulations were necessary to protect public health. The EPA reported its study to Congress in February 1998. After completion of the study, the EPA was required to determine whether to proceed with the development of regulations. In the December 2000 announcement, the EPA affirmed its decision that Hg emissions from power plants should be regulated.

Although neither the DNR nor the EPA have draft rules in place, previous DNR and legislative initiatives in Wisconsin envisioned a flexible, cap-and-trade Hg control program similar to the federal Acid Rain Program, and set reduction targets at 50 to 90 percent for utility systems emitting greater than 100 pounds per year of mercury. Other sources emitting greater than 10 pounds per year would be affected by a mass emission cap. The petition to the DNR sought a 90 percent reduction in Hg emissions from utility and government-owned boilers, municipal waste incinerators, and medical incinerators, among other potential sources, by 2010. Regulations of Hg emissions, as well as emissions of other pollutants are discussed in the next section of this chapter.

DNR's Proposed Permitting Process (p. 141)

The EPA has approved Wisconsin's Air Permitting and review authority under the Clean Air Act.

WEPCO has submitted a Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR) permit application for the Elm Road Generating Station (ERGS) to the DNR under Wis. Admin. Code chs. NR 405, NR 406, and NR 408, and the Code of Federal Regulations, 40 CFR S. 52.21. The DNR has not yet declared the application complete.

This section of the EIS describes the numerous aspects of air pollution regulation as they relate to the ERGS project.

Applicable Air Quality Standards

National Ambient Air Quality Standards (p. 141)

The federal Clean Air Act requires the EPA to establish National Ambient Air Quality Standards (NAAQS) for air pollutants that could adversely impact human health or welfare. Primary standards have been established to protect public health, while the secondary standards have been established to protect public welfare and the environment. NAAQS have been established for the following pollutants, collectively referred to as "criteria pollutants."

- Sulfur dioxide (SO2)

- Nitrogen oxides (NOx)
- Carbon monoxide (CO)
- Particulate matter less than 10 microns in diameter (PM10)
- Ozone—volatile organic compounds (VOC) must be considered
- Lead

EPA describes an area as "non-attainment" if the ambient air quality standard for one or more criteria pollutants is not met. (See a general discussion on "non-attainment areas" earlier in this chapter).

The Clean Air Act Amendments of 1972 resulted in a national permitting program for all areas of the country in 1977. Areas in which the existing air quality meets the NAAQS are subject to the rules of the Prevention of Significant Deterioration Program. Areas in which the existing air quality does not meet the NAAQS are subject to non-attainment area New Source Review (NSR) requirements. The analysis as to whether or not an area meets the NAAQS is done on a pollutant-by-pollutant basis.

The state of Wisconsin regulates air pollutant emissions under Wis. Admin. Code Chapters 400-499 and has adopted the EPA primary and secondary standards. All counties in Wisconsin are classified either as "attainment" (their ambient air has less of that pollutant than the standard allows) or "non-attainment" (their ambient air has more of that pollutant than the standard allows). In addition, Wisconsin has a secondary or welfare-based standard for Total particulate matter (PM).

The area of the state that would include the ERGS is presently classified as severe non-attainment for ozone. The area is presently classified as attainment for all other criteria pollutants. The proposed project is classified as a major modification to the existing OCPP major stationary source for Prevention of Significant Deterioration (PSD) and New Source Review (NSR) regulatory purposes. Therefore, a PSD permit application is required for all pollutants emitted by the ERGS above the PSD significant emission levels and a non-attainment area NSR permit is required for the volatile organic compounds emission. See Table 7-9.

Non-attainment new source review requirements (p. 142)

Because the area of the project is non-attainment for ozone, a non-attainment area NSR permit is required for VOC emissions, which are precursors of ground level ozone formation.

In addition, the non-attainment area NSR regulations under Wis. Admin. Code ch. NR 408 require the application of the lowest achievable emission rate (LAER) control technology to all VOC emissions sources. The NR 408 regulations also require that WEPCO obtain VOC emissions offsets for the potential VOC emissions from this project. WEPCO needs to obtain offsets at a rate of 1.3 to 1 for the emission increases from this project.

Prevention of significant deterioration (p. 142)

In addition to the NAAQS, the PSD program under 40 CFR Part 52 and Wis. Admin. Code ch. NR 405 has established maximum allowable ambient air "increments." These increments were established at approximately 20 to 40 percent of the primary or secondary standard, and were intended to limit the deterioration of air quality in a "PSD region." Once an application for a PSD source in a given county is deemed complete, the PSD baseline is established by the DNR in the area in which the source is located. If the PSD baseline has been established for a pollutant by another source, all new projects, including minor sources, are required to limit their maximum ambient air impacts to levels at or below the PSD increments. The PSD program objectives are:

1. To ensure that economic growth will occur in harmony with the preservation of existing clean air resources.

2. To protect the public health and welfare from any adverse effect that might occur even at air pollution levels better than the NAAQS.

3. To preserve, protect, and enhance the air quality in areas of special natural recreational, scenic, or historical value, such as national parks and wilderness areas.

Proposals submitted after the PSD baselines have been set are modeled along with existing and permitted facilities. The combined modeling determines how close their combined emissions would come to using up all the capacity of the area to receive pollutants at a specific location around the proposed site. This capacity would be limited by the air quality standards. The standard measurement is called the "PSD increment." The total impact at any point, from all sources that have been constructed or modified after the baseline date, including the proposal, must not exceed the incremental level. If a proposed project exceeds the increment, it cannot be permitted unless it is modified to reduce the proposed emissions, or unless a reduction in emissions elsewhere leaves some additional increment that can be utilized.

The provisions of the PSD program apply to major new sources and major modifications of existing "major sources" constructed in areas where existing ambient air quality meets the NAAQS. Major sources are those sources that have the potential to emit more than 100 tons per year (tpy) of any one of the criteria pollutants listed in one of 28 specific pre-designated categories, or 250 tons per year of criteria pollutants in all other source categories.

The major elements of a PSD review include:

- Control Technology Review (Wis. Admin. Code § NR 405.08)
- Air Quality Analysis (Wis. Admin. Code § NR 405.11)
- Source Impact Analysis (Wis. Admin. Code § NR 405.09)
- Additional Impacts Analysis (Wis. Admin. Code § NR 405.13)

Control technology review (p. 143)

One of the requirements of the PSD program is that the Best Available Control Technology (BACT) be installed for all pollutants regulated under the NR 405 ~~Act~~ that would be emitted in significant amounts from new major sources or modifications of existing major sources. The

PSD requirements require the application of BACT to each source of emissions subject to PSD review. The BACT is determined based on what controls have recently been permitted or are in operation at similar facilities. All new major stationary sources must apply BACT for each regulated air contaminant that they will have the potential to emit in significant amounts. The determination of BACT is discussed later in this chapter.

Top-down approach to BACT (p. 144)

Any control technology (BACT) review must include an evaluation of environmental, energy, technical, and economic impacts. Currently, the EPA and the WDNR ~~is~~ are recommending a "top-down" approach in conducting a BACT analysis. The first step in the top-down BACT approach is to determine the most stringent control available for a similar source or source category. If it is shown that the level of control is technically or economically infeasible for the source in question, then the next level of control is determined and similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any substantial or unique energy, environmental, or economic impact.

The energy impact analysis estimates the direct energy impacts of the control alternatives in units of energy consumption. If possible, the energy requirements for each control option are assessed in terms of total annual energy consumption. The net environmental impact associated with a control alternative is considered through the use of computer driven air dispersion modeling analyses. The economic impact of a control option is assessed in terms of cost effectiveness.75

Once the energy, environmental, and economic impacts are assessed, the level of control achieved through the use of the technology being evaluated is determined to be BACT.

New Source Performance Standards (p. 144)

Section 111 of the Clean Air Act and NR440 establishes a regulatory scheme for controlling emissions of criteria air pollutants from identified source categories. Any construction or reconstruction of a source for which a New Source Performance Standard (NSPS) has been set is subject to that standard if construction or reconstruction occurs on or after the date the standard was proposed by the EPA. The requirements of 40 CFR 60 are the NSPSs for new or modified units. Either they set the base, or the minimum control requirements for BACT set the base of emission control if they are more stringent. NSPS requirements are discussed below.

The following general NSPS requirements apply (under 40 CFR Part 60, Subpart A, and Wis. Admin. Code ch. NR 440) to any affected emission unit that is subject to a specific NSPS:

- Notification and recordkeeping
- Performance tests
- Compliance with standards and maintenance requirements
- Monitoring

In addition, there are more detailed requirements for specific technologies. These are as follows.

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75 The economic impacts are reviewed on a cost per ton controlled basis, as directed by the EPA's Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual, Fifth Edition..

SCPC boilers

The SCPC boilers would be subject to Subpart Da because they are electric utility steam generating units with heat inputs greater than 250 mmBtu/hr. The applicable Subpart Da emission limitations are summarized in Table 7-3.

Table 7-3 NSPS emission limits for SCPC boilers

Pollutant	NSPS limit	Reduction Requirements	Averaging period
PM	0.03 lb/mmBtu*	99 percent	-
Visible emissions	20 percent opacity	-	-
SO_2	-	-	-
Coal	1.2 lb/mmBtu	90 percent **	30 day rolling average
Distillate oil	0.20 lb/mmBtu	0%	-
NO_x	1.6 lb/MW-hr	-	30 day rolling average

*** The particulate emission standard under Ch. NR 440.20 does not include condensable particulate matter.**
**** The NSPS limit varies depending upon fuel sulfur content, with a 90 percent reduction and 1.2 lb/mmBtu limitation or a 70 percent reduction when emissions are below 0.60 lb/mmBtu.**

SCPC auxiliary boiler

The SCPC auxiliary boiler would be subject to Subpart Db, because this boiler would fire diesel oil. It would be subject to the emission limits and continuous emissions monitoring requirements under Wis. Admin. Code § NR 440.205 for NOx, PM, and SO2. However, the sulfur percentage of the diesel would not exceed 0.05 percent by weight, less than the 0.5 weight percent threshold for "very low sulfur oil" under 40 CFR 60.41. Affected sources combusting only very low sulfur oil are not subject to federal percent reduction requirements and not required to conduct performance testing or install and operate continuous monitors for SO2 if fuel receipts are maintained.

SO2 and PM standards for opacity would be applicable. Any gases emitted from each stack when the units are diesel-fired would not be allowed opacity greater than 20 percent (six-minute average). The exception is one six-minute period per hour with opacity not exceeding 27 percent. The opacity standard would not apply during periods of startup, shutdown, or malfunction, but a continuous opacity monitor would be installed for when diesel is burned in the boiler.

Because this boiler would be designed as a low heat release rate boiler (a maximum heat release rate of less than 70,000 Btu/hr-ft3), the maximum allowable NOx emission would be 0.10 lb/mmBtu, regardless of whether the diesel or natural gas is burned. Compliance with the NOx emission limit is to be determined on a 30-day rolling average basis and applies at all times, including startup, shutdown, and malfunctioning.

IGCC auxiliary boiler

The IGCC auxiliary boiler would be subject to NSPS under Subpart Dc and NR 440.207 because it would have a heat rate between 10 and 100 mmBtu/hr. It would be subject to emission limits and opacity standards for PM and SO2 when burning diesel. The allowable SO2 emission limit would be 0.5 lb/mmBtu. With the diesel at less than 0.05 percent sulfur by weight, the estimated SO2 emission rate would be 0.056 lb/mmBtu, which is significantly below the allowable SO2 limit. Compliance with the limitation might be determined based on a certification from the fuel supplier and monitoring.

In terms of opacity standards, any gases emitted from the stack when diesel was fired would not be allowed opacity greater than 20 percent (six-minute average). The exception would be one six-minute period per hour with opacity not exceeding 27 percent. The opacity standard would not apply during periods of startup, shutdown, or malfunction, and a continuous opacity monitor would not be required.

IGCC stationary natural gas turbines

As specified, Subpart GG applies to any stationary gas turbine with a heat input at peak load greater than or equal to 10.7 gigajoules/ hour (10.1 mmBtu/hour) and which begins construction, reconstruction, or modification after Oct. 3, 1977. Each of the two proposed IGCC stationary gas turbines would be rated at a peak load heat input of approximately 2,139 mmBtu/hr when combusting syngas, so they would qualify. Subpart GG contains NOx and SO2 emission standards and associated monitoring, record keeping, and reporting requirements. However, the BACT requirements of PSD are more stringent than the NOx and SO2 emission standards contained in Subpart GG, so BACT would be more stringent than these NSPSs.

Coal handling and storage

The coal handling and storage operations would subject to Subpart Y and NR 440.42. For these operations, NR 440.42 would prohibit visible emissions of 20 percent opacity or greater from any coal processing and conveying equipment, coal storage system (except open storage), or coal transfer and loading systems.

Limestone handling and storage

The limestone materials handling and storage operations, with the exception of the open storage piles and railcar or truck dumping operations, would be subject to Subpart 000 and NR 440.688. These limitations are summarized in Table 7-4 below. The acronyms "gr/acf" and "gr/dscf" indicated "grains per actual cubic feet" and "grains per dry standard cubic feet," respectively.

Table 7-4 ERGS operations related to limestone handling and storage, and emission limits required under NSPS

Operation	NSPS Emission Limits
Limestone silos and receiving hoppers	0.022 gr/acf; 7 percent opacity
Limestone dryer/mill building vents and exhaust	No visible emissions; 0 percent opacity
Limestone dryers/mills	0.022 gr/dscf; 7 percent opacity
Limestone crusher/conveyor transfers	0.022 gr/dscf; 7 percent opacity
Limestone conveyors, transfer points, and enclosures	10 percent opacity

Air quality analysis (p. 146)

The PSD program requires an air quality analysis for each regulated pollutant under NR 405 that a proposed major source would emit at levels greater than the significant emissions level. The purpose of the air quality analysis is to demonstrate, through the use of air quality dispersion models and background ambient data, that allowable emission increases from the proposed source, combined with emissions from other sources will not cause or contribute to violations of any Wisconsin Ambient Air Quality Standards or NAAQS, or any applicable maximum allowable increases over the baseline concentration in any area including PSD increments.

Currently, DNR is completing its modeling analysis. The air quality analysis information in the draft EIS is based on the air pollution control permit application information provided by WEPCO.

Source impact analysis (p. 146)

All owners and operators of new major stationary sources must demonstrate that allowable emission
increases from the proposed major source, in conjunction with all other applicable emissions increases would not cause or contribute to air pollution in violation of the NAAQS and PSD increment. The NAAQS compliance demonstration would be performed by adding the measured

existing background ambient air levels to the modeled impacts from the proposed project and all other explicitly modeled sources in the NAAQS source inventory. The total modeled impact is compared to the NAAQS.

The PSD increment compliance demonstration would be performed by modeling actual emission changes that have occurred since the baseline date. The total ambient air quality concentration change would then be compared to the applicable PSD increment.

Additional impacts analysis (p. 147)

All applications for operation permits must provide an analysis of the potential impairment to (1) visibility, (2) soils, and (3) vegetation that would occur as a result of both the major source and the general commercial, residential, industrial, or other growth associated with the major source. Preliminary DNR conclusions are discussed later in this chapter.

Federal Acid Rain Program (p. 147)

Title IV of the 1990 Clean Air Act Amendments established the federal Acid Rain Program, which sets as its primary goal the reduction of acid deposition through reductions in emissions of SO2 and NOx, the primary causes of acid rain. The Acid Rain Program established a system to reduce the total U.S. annual SO2 emissions by 50 percent from 1980 levels. This reduction is equal to an annual reduction of 10 million tons per year. To achieve this goal at the lowest cost to society, the program employs a market-based approach for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention.

The Acid Rain Program affects existing utility generators with an output capacity of greater than 25
megawatts and all new utility units. During Phase II of the program, which began in 2000, the Act sets a permanent annual ceiling (or cap) of 8.95 million "allowances" (one allowance is equal to one ton of SO2 emissions) as the total annual allowance allocation to utilities. This cap firmly restricts emissions and ensures that environmental benefits will be achieved and maintained, even when new facilities are constructed.

The SCPC boilers and the IGCC turbines would be subject to the provisions of the federal Acid Rain Program requirements in 40 CFR Parts 72 to 76, so an acid rain permit application has been submitted. The units would need to employ monitoring consistent with 40 Part 75 at the time that each boiler and IGCC unit begins initial operation.

Hazardous air pollutants (p. 147)

Case-by-case MACT
The EPA's regulation of hazardous air pollutants (HAPs) has, since 1996, involved a case-by-case maximum achievable control technology (MACT) as set out in 40 CFR Part 63 Subpart B. Those regulations require case-by-case determinations of MACT for each "major source" of HAPs constructed or reconstructed after an effective date which are listed by EPA and have yet

to have a MACT standard promulgated. Electric utility steam generating units had been exempted from the case-by-case provisions because they were not yet added to the source category list. On December 14, 2000, the EPA added coal- and oil-fired power plants to the Section 112(c) list of HAP sources, making coal- or oil-fired electric utility steam generating units that are constructed or reconstructed after December 14, 2000 subject to the case-by-case provisions until the EPA promulgates a nationally applicable MACT standard to address them. The EPA expects to promulgate a final standard in 2004. Thus, a case-by-case MACT determination for the ERGS SCPC units would need to be completed.

Major sources of HAP emissions are defined as sources with the potential to emit 10 tpy of any individual HAP or 25 tpy on any combination of HAPs listed in Section 112(b)(1) of the Clean Air Act Amendments.

IGCC units are not included in a source category yet. However, simple-cycle combustion turbines are listed as a source category under Section 112(c). Based on a broad interpretation of EPA's interpretive rule, dated May 25, 2000, the HAP emissions associated with the IGCC CTs need to be considered when determining major source thresholds.

There are two basic MACT concepts in the case-by-case technology determination:

1. The MACT emission limitation or requirements recommended by the applicant shall not be less stringent than the emission control which is now achieved in practice by the best controlled similar source.

2. Based upon available information, the MACT emission limitation and control technology shall achieve the maximum degree of HAP emissions reduction that can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.

General HAP requirements (p. 148)

Since the proposed SCPC and IGCC units would each be subject to a regulation contained in 40 CFR Part 63, they would also have general notification, record keeping, and monitoring requirements under 40 CFR Part 63, Subpart A.

Prevention of accidental releases (p. 148)

The CAA amendments of 1990 include language that requires chemical accident prevention provisions at affected facilities. Affected facilities are those stationary sources that store, use or handle any of 140 listed hazardous substances in amounts greater than the listed threshold quantities. Section 112(r) of 40 CFR Part 58, "Prevention of Accidental Releases," establishes the requirements for owners and operators of stationary sources that produce, process, handle or store any of the regulated chemicals. The purpose of this requirement is to prevent and mitigate accidental releases of these substances by preparing a detailed risk assessment and implementing a number of safety procedures through the preparation of a Risk Management Plan.

WEPCO has stated its intention to do an analysis after the plant design is finalized to determine if it would store any of the listed chemicals or substances in quantities near or above the threshold levels. It has also stated its intention to comply with the general duty clause of the CAA, Section 112(r)(1).

Compliance Assurance Monitoring (p. 148)

The Compliance Assurance Monitoring (CAM) rule (40 CFR Part 64) establishes criteria for monitoring certain existing air pollution control devices to provide reasonable assurance of compliance with emission limits and standards. As specified in 40 CFR § 64.2(a), the CAM rule applies, on a pollutant-specific basis, to each emission unit at a major source if it:

- Is subject to an emission limitation or standard for the pollutant.
- Uses a control device to achieve compliance with the limit or standard.
- Has the potential for uncontrolled emissions of the pollutant equal to or greater than the major source threshold for that pollutant (in this case, 100 tpy of any criteria pollutant, 10 tpy of any individual HAP, or 25 tpy of any combination of HAPs).

However, 40 CFR 64.2(b)(1)(iii) specifies an exemption from the CAM rule for emission units (on a pollutant-specific basis) that are subject to Acid Rain Program requirements. It remains to be seen whether the CAM rule would apply to the SCPC units. WEPCO has indicated that it believes that the CAM rule would not apply to the IGCC unit because, while NOx and SO2 qualify the two natural gas turbines, those turbines are subject to Acid Rain Program requirements for those two pollutants. The DNR is in the process of verifying this point.

Mercury (p. 149)

Although neither the DNR nor the EPA have rules in place, previous DNR and legislative initiatives in Wisconsin envisioned a flexible, cap-and-trade mercury control program similar to the federal Acid Rain Program, with reduction targets at 90 percent. Point sources with actual mercury emissions of more than 10 pounds per year would need to comply. Until such rules are made law, mercury still qualifies under the case-by-case MACT requirement for the SCPC units.

State requirements (Wisconsin) (p. 149)

Opacity
According to Wis. Admin. Code ch. NR 431, the opacity from the SCPC units and the IGCC unit shall not be greater than 20 percent except during cleaning periods for combustion equipment. During those cleaning periods, emissions are allowed to exceed 20 percent but may not exceed 80 percent for 5 minutes in any one hour.

Control of nitrogen compound emissions (p. 149)
As specified in Wis. Admin. Code § NR 428.04, NOx requirements and performance standards for new or modified sources apply to emission units located in Kenosha, Milwaukee, Ozaukee, Racine, Washington, or Waukesha County that are constructed or that undergo a major modification after February 1, 2001.

The proposed SCPC boilers would qualify because they would have a maximum design heat input of more than 250 mmBtu per hour. The performance standard is 0.15 pounds per mmBtu heat input on a 30-day rolling average. Additionally, NR 428 contains both general and specific notification, monitoring, and record keeping requirements. The IGCC unit would be subject to an emission limit of 15 ppm at 15 percent O2 on a 30-day rolling average, in accordance with Wis. Admin. Code § NR 428.04(g)(3).

Particulate matter (p. 150)
The SCPC and IGCC units are subject to Wis. Admin. Code § NR 415.06 and have an allowable emission rate of 0.1 lb/mmBtu, for fuel burning sources that have a heat input of greater than 250 mmBtu/hr and emit PM.

Hazardous air pollutants (p. 150)
The state of Wisconsin regulates the emissions of hazardous air pollutants under Wis. Stat. ch. NR 445. NR 445 exempts fuels that meet the definition of a "Virgin Fossil Fuel." Virgin fossil fuels are defined as any solid, refined liquid or refined gas fossil fuels with Btu contents greater than 7,000 Btu/lb that are not blended with reprocessed or recycled fuels. Natural gas, liquid petroleum gas, fuel oil, distillate fuel oil, gasoline, and diesel fuel are Group 1 virgin fossil fuels. Coal and residual fuel oil would be Group 2 virgin fossil fuels.

Ammonia might be emitted as a result of ammonia "slip" from the SCR system for NOx emission control. Ammonia is a regulated HAP under NR 445, Table 1.

Wisconsin's climate change action plan (p. 150)
The DNR, in cooperation with other agencies and organizations, has recently completed the Wisconsin Greenhouse Gas Emission Reduction Cost Study. The study states that Wisconsin's greenhouse gas by 21 million tons in 2010 by switching coal-fired power plants to natural gas. This change would double the state's consumption of natural gas. The study results estimate the cost for switching electric utility coal-fired power plants to natural gas would be about $460 million. However, this cost does not include the cost of expanding and extending natural gas pipelines and the associated environmental impacts or the potential increase in natural gas prices that this increased use of natural gas could cause.

The study suggests that energy efficiency savings may balance the cost of fuel switching. However, natural gas prices have increased dramatically since this study was completed. In order to realize the energy efficiency gains suggested in the study, a more rigorous and concerted effort on the part of the state regulatory agencies and the regulated community as a whole would be required. To that end the Wisconsin Climate Change Action Plan envisions specific "actions to implement energy efficiency measures." These actions call for the Wisconsin state government to:

• Lead by example.
• Vigorously promote voluntary, private sector-led initiatives to adopt energy efficiency measures.
• Provide financial incentives for adopting energy efficiency measures.
• Revise or update existing building codes to support energy efficient improvements.
• Perform "actions to promote a shift to a higher proportion of cleaner energy sources."

These actions are to include having the state government:

o Lead by example.
o Vigorously promote voluntary, private sector-led initiatives to move toward cleaner energy
sources and technologies.
o Provide financial incentives to increase renewable energy use.
o Participate actively in research and development projects designed to reduce emissions per
unit of energy generated.

Currently, there are no regulatory requirements for individual projects such as the proposed ERGS to reduce or eliminate CO_2 emissions. At any rate, requirements to reduce emissions from this facility may be counterproductive if those requirements restrict this facility's utilization, since this project would be more efficient than the existing coal-fired generation equipment that it would displace. In that sense, limiting the deployment of new, modern power plants such as the ERGS may not be the best means to ultimately reducing greenhouse gas emissions.

Expected schedule of air permitting (p. 151)
WEPCO proposes to begin construction of the two SCPC units in 2003. The in-service dates for the first and second SCPC units would be 2007 and 2009. WEPCO proposes that the IGCC will be put in service in 2011.

After the final air pollution permit is issued, WEPCO would be given 90 months by the DNR to complete the construction of the entire project. WEPCO will be required to submit information for reevaluating BACT to the DNR at least 18 months prior to the commencement of construction of any permitted processes that may have not begun construction within eighteen months from the date of the issuance of the final permit.

Ambient Air Quality (p. 151)

Regional climate
Several factors control the climate of the Great Lakes region. The most important of these are:

Latitude
- Continental location

- Large-scale circulation patterns
- The lakes themselves

The Great Lakes are large enough to have significant impacts on local weather.

Temperature (p. 151)
Overall, the region can be described as having warm summers and cold winters. For the period 1971-2000, average daily summer temperatures range from daytime highs of 81 o F to nighttime lows of 63 o F. Average daily winter temperatures range from daytime highs of 28 o F to nighttime lows of 13 o F. The average annual temperature is 48 o F.
The average summer temperature is 70 o F, and the average maximum summer temperature is 79 o F. In winter, the average temperature is 24 o F, and the average minimum temperature is 17 o F. Yearly, daily maximum temperatures will exceed 90 o F an average of nine times, while daily minimum temperatures will be below 32 o F an average of 133 times. Record temperatures since 1942 range from 103 o F (August 1, 1988 and July 13, 1995) to -26 o F (January 17, 1982 and February 3, 1996).

Precipitation (p. 152)
Average historical precipitation data for the period from 1971 to 2000 are presented in Table 7-5. Total annual precipitation averages 34.8 inches, while historic extremes from 1927 to the present, range from a maximum of 44.4 inches in 2000 to a minimum of 19.1 inches in 1963. Annual snowfall averages 52.6 inches with an all-time high of 93.3 inches in 1959-1960.

Table 7-5 Temperature and precipitation data for Oak Creek

Month	Temperature (^oF)			Precipitation (inches)			
				Rainfall		Snowfall	
	Maximum	Minimum	Mean	Mean	High	Mean	High
January	28.0	13.4	20.7	1.85	4.38	15.3	39.0
February	32.5	18.3	25.4	1.65	3.94	11.3	42.0
March	42.6	27.3	34.9	2.59	6.93	7.4	30.3
April	53.9	36.4	45.2	3.78	7.31	2.6	15.8
May	66.0	46.2	56.1	3.06	9.68	0.1	3.2
June	76.3	56.3	66.3	3.56	9.98	0.0	0.0
July	81.1	62.9	72.0	3.58	7.66	0.0	0.0
August	79.1	62.1	70.6	4.03	9.05	0.0	0.0
September	71.9	54.1	63.0	3.30	9.87	0.0	0.0
October	60.2	42.6	51.4	2.49	7.03	0.4	6.3
November	45.7	31.0	38.4	2.70	7.11	3.7	16.1
December	33.1	19.4	26.2	2.22	5.42	11.8	49.5

Wind

Based on the *Wind Atlas of Wisconsin, 1996* (Wisconsin Geological and Natural History Survey Bulletin 94), the overall average wind speed from the nearest National Weather Service Station (Milwaukee) is 11.4 mph. The predominant wind directions are westerly, varying from west-northwesterly in the winter to southwesterly in the summer. However, due to the effect of Lake Michigan, the prevailing winds during the late spring (April, May, and into early June) is from the north-northeast.

Oak Creek Air Quality (p. 152)

Ambient Air Quality Standards
Standards for ambient air quality in Wisconsin are codified under Wis. Admin. Code ch. NR 404. WEPCO applied to receive air pollution control permits for all three proposed power plant site options. The ambient air quality standards for the ERGS are summarized for the North and South site alternatives in Tables 7-6 to 7-8.

Prevention of significant deterioration (p. 153)
Milwaukee is a PSD county, and the baselines have already been established for particulate matter less than ten micrometers in diameter (PM10), sulfur dioxide (SO2), and nitrogen oxides (NOx). When the DNR Bureau of Air Management deems the company's PSD applications complete, the project would be expected to set the baselines for all three pollutants for Racine County. Therefore, the concentrations of the air pollutants from the proposed project are subject to the corresponding PSD increment limits. The PSD increment levels are summarized in Tables 7-6 to 7-8 for the three ERGS site alternatives.

Existing air quality (p. 153)
Attainment or non-attainment areas are classified based on ambient air quality data collected at monitoring sites around the state. Milwaukee and Racine Counties are classified as attainment for all pollutants except ozone. Both counties are classified as severe non-attainment for ozone. This criteria pollutant's background concentrations for Milwaukee and Racine Counties are summarized in Tables 7-6 to 7-8. 76

Table 7-6 Criteria air pollutant background concentrations, PSD increments, and NAAQS for Milwaukee County and the North Site

Parameter	Averaging Period	Milwaukee County: Background Concentration (micrograms/m^3)	Milwaukee County: PSD Increment Level (microgram/m^3)	NAAQS (micrograms/ m^3)
Total suspended particulate (TSP)	24-hour	76	NA	150
PM_{10}	Annual	27	17	50
PM_{10}	24-hour	58	30	150
SO_2	Annual	9.3	20	80

SO_2	24-hour	7.8	91	365
SO_2	3-hour	208.1	512	1,300
CO	8-hour	3,274.2	NA	10,000
CO	1-hour	4,319.6	NA	40,000
NO_x	Annual	31	25	100
Pb	Calendar quarter	NA	NA	1.5

76 The information in these tables is based on WEPCO's information in its air permit application. The data is subject to change pending DNR's further review and analysis.

Table 7-7 Criteria air pollutant background concentrations, PSD increments, and NAAQS for Racine County and the South Site

Parameter	Averaging Period	Racine County		NAAQS (micrograms/ m^3)
		Background Concentration (micrograms/m^3)	PSD Increment Level (microgram/m^3)	
Total suspended particulate (TSP)	24-hour	76	NA	150
PM_{10}	Annual	27	17	50
PM_{10}	24-hour	58	30	150
SO_2	Annual	9.3	20	80
SO_2	24-hour	57.8	91	365
SO_2	3-hour	208.1	512	1,300
CO	8-hour	3,274.2	NA	10,000
CO	1-hour	4,319.6	NA	40,000
NO_x	Annual	31	25	100
Pb	Calendar quarter	NA	NA	1.5

Table 7-8 Criteria air pollutant background concentrations, PSD increments, and NAAQS for Racine County and South Site-Exp

Parameter	Averaging Period	Racine County		NAAQS (micrograms/m^3)
		Background Concentration (micrograms/m^3)	PSD Increment Level (microgram/m^3)	
Total suspended particulate (TSP)	24-hour	76	NA	150
PM_{10}	Annual	27	17	50
PM_{10}	24-hour	58	30	150
SO_2	Annual	9.3	20	80
SO_2	24-hour	57.8	91	365
SO_2	3-hour	208.1	512	1,300
CO	8-hour	3,274.2	NA	10,000
CO	1-hour	4,319.6	NA	40,000
NO_x	Annual	31	25	100
Pb	Calendar quarter	NA	NA	1.5

Expected Emissions & Proposed Best Available Control Technology (p. 154)

Pollution source descriptions

The sources of air pollutant emissions from the proposed ERGS are included in WEPCO's PSD construction permit application and additional information submitted to the DNR. The sources are identical for each proposed site option. The emission sources included in the permit application were:

- Two 615 megawatt (MW) supercritical pulverized coal (SCPC) electric generating units
- One 600 MW integrated gasification combined cycle (IGCC) unit
- Two auxiliary boilers
- Two emergency diesel generators
- Three diesel fire pumps
- Fuel storage tanks
- Coal handling and other material handling equipment

Expected project emissions (p. 154)

Potential emissions from the proposed project are estimated based on the worst-case operating scenarios, taking into account control equipment and federally enforceable conditions expected to be in the power plant's permit. Table 7-9 summarizes the potential annual emissions to the air expected from various components of the proposed ERGS and the total facility in tons per year (tpy), once all three phases are operational.77

Table 7-9 Estimated annual emissions of the project in tons per year

Pollutant	**Two SCPC Units**	**IGCC Unit**	**SCPC & IGCC Auxiliary Boilers**	**Diesel Equipment**	**Material Handling Point Sources**	**Fugitive Dust Sources**	**Storage Tanks**	**Facility Total (tpy)**
CO	6,496.0	564.0	23.1	23.1				**7,106**
NO_x	3,811.0	1,396.0	20.0	27.2				**5,254**
PM	974.0	199.0	5.4	1.1	120.0	359.1		**1,659**
PM_{10}	974.0	199.0	5.4	1.1	120.0	171.7		**1,471**
SO_2	8,662.0	1,117.0	0.59	0.0				**9,780**
VOC	189.0	79.0	2.1	2.7			0.0025	**273**
Hg	0.12	0.03	0.00033	0.00				**0.15**
Be	0.017	0.03	0.00026	0.00				**0.048**
Fluorides (as HF)	48.0	0.50	0.0	0.00				**49**
Sulfuric Acid Mist	541.0	26.0	0.12	0.00				**567**
Pb	0.40	0.50	0.00078	0.00				**0.90**

Ammonia (NH_3)	175.2	-	-	-				**175**

Ammonia is also a pollutant regulated under NR 445. It is discussed along with other expected toxic
pollutant emissions later in this chapter. The estimate of potential SCPC boiler ammonia emissions is based on a proposed SCR emission rate of 5 ppm dry volume (ppmdv).

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77 Based on WEPCO's calculations in its permit application information. This data is subject to change pending DNR's further review and analysis.

Table 7-10 Net change in emissions and PSD significance levels

Pollutant	Net Emissions Change (tpy)	PSD Significance Level (tpy)	PSD Review Required? (Yes/No)
CO	7,106	100	Yes
NO_x	5,254	40	Yes
PM	1,659	25	Yes
PM_{10}	1,471	15	Yes
SO_2	9,780	40	Yes
VOC	273	25 for New Source Review	Yes
Pb	0.90	0.6	Yes
Hg	0.15	0.1	Yes
Be	0.05	0.0004	Yes
F (as HF)	49	3	Yes
Sulfuric acid Mist	567	7	Yes

Table 7-10 illustrates WEPCO's estimates of project emission increases compared to their PSD significance levels.78 If the emission of any pollutant increase is at a level that is greater than the PSD significance level, the project is subject to PSD for that pollutant.
Based on Table 7-10 above, the proposed facility is classified as a major source under both the operation permits program in Wis. Adm. Code ch. NR 407, and the New Source Review programs under Wis. Adm. Code chs. NR 405 and NR 408. Because the facility belongs to one of the 28 pre-designated categories and would have potential emissions of at least one of the criteria pollutants in amounts greater than 100 tpy, it is subject to PSD review.

This table and Table 7-9 also show that CO, PM, PM10, SO2, sulfuric acid mist, NOx, Pb, Hg, Be, and HF would all be emitted in quantities in excess of the PSD significant levels under Wis. Admin. Code § NR 405.02(27)(a), Table A. _As a result, these pollutants are subject to the control technology review requirements of Wis. Admin. Code § NR 405.08.

Tables 7-9 and 7-10 also show that VOC emissions would be subject to non-attainment New Source Review under Wis. Admin. Code ch. NR 408, and subject to the lowest achievable emission rate (LAER) control technology. NR 408 also requires WEPCO to obtain VOC emissions offsets for the potential VOC emissions from this project at a rate of 1.3 to 1.

78 Based on WE Energy's calculations in its permit application information. This data is subject to change pending DNR's further review and analysis

Proposed BACT (p. 157)

The top down BACT approach was utilized by WEPCO in its BACT analysis for the numerous potential emission sources in the proposed ERGS project. The required BACT is still being assessed by the DNR.

The proposed BACT controls for each potential project emissions source at the three proposed alternative sites are summarized in Tables 7-11 through 7-22. The data in these BACT-LAER tables is also based on WEPCO's permit application information and does not reflect DNR analysis, which is still in progress. It is subject to change pending DNR's further review and analyses. The emissions sources include boilers, diesel engines, and materials handling systems.

Table 7-11 indicates the proposed BACT for the PSD pollutants expected to be emitted by the SCPC units. This information is subject to change pending DNR's further review and analysis. A combination of low-NOx burners, SCR, the fabric filter baghouse, FGD, and a wet electrostatic precipitator are proposed. The acronyms "mmBTU" and "ppmdv" stand for "pounds per million BTUs" and "parts per million by dry volume," respectively.

Table 7-11 BACT and LAER for SCPC boiler emissions, based on WEPCO's permit application

Pollutant	Proposed Control Technology (BACT)	Proposed Limit (LAER)
CO	Low NO_x burners and good combustion practices	0.12 lb/mmBtu 742 lbs/hr (See Note 1)
NO_x	Low NO_x burners selective catalytic reduction	0.07 lb/mmBtu < 5 ppmdv ammonia (See Note 2)
PM	Fabric filter baghouse and flue gas desulfurization	0.018 lb/mmBtu 20% opacity (See Note 3)
PM_{10}	Fabric filter baghouse and flue gas desulfurization	0.018 lb/mmBtu 20% opacity (See Note 3)
SO_2	Wet flue gas desulfurization	0.16 lb/mmBtu and 3,708 lbs/hr (See Notes 2 and 5)
VOC *See Note 4*	Low NOx burners and good combustion practices	0.0035 lb/mmBtu 21.6 lbs/hr (See Notes 1 and 6)
Pb	Fabric filter baghouse and flue gas desulfurization	7.9 lb/trillion Btu (See Note 3)
Hg	Fabric filter baghouse and flue gas desulfurization	2.3 lb/trillion Btu (See Note 2)
Be	Fabric filter baghouse and flue gas desulfurization	0.35 lb/trillion Btu (See Note 2)
Fluorides	Fabric filter baghouse and flue gas desulfurization	0.00088 lb/mmBtu (See Note 2)
Sulfuric Acid Mist (H_2SO_4)	Flue gas desulfurization and wet electrostatic precipitator	0.01 Lb/mmBtu (See Note 2)

Note 1: Based on an 8-hour average
Note 2: Based on a 12 month rolling average limit
Note 3: Based on a 3 hour block average limit
Note 4: This limit is based on a 96 percent reduction in the emission rate of the design bituminous coal.
Note 5: Based on a 24 hour average.
Note 6: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table 7-12 shows the proposed BACT for the expected SCPC auxiliary boiler emissions. This information is subject to change pending DNR's further review and analysis. A combination of low-NOx burners, "good " and use of natural gas or ultra-low-sulfur fuel oil are proposed. WEPCO has elected an operating limit of no more than 2,000 hours per year, of which no more than 500 hours per year is firing fuel oil.

Table 7-12 BACT and LAER for the auxiliary boiler for the SCPC boiler, based on WEPCO's permit application

Pollutant	Proposed Control Technology (BACT)	Proposed Limit (LAER)
CO	Low NO_x burners and good combustion practices	0.075 lb/mmBtu *See Note 1*
NOx	Low NO_x burners	0.036lb/mmBtu when firing natural gas; 0.12 lb/mmBtu when firing fuel oil *See Note 1*
PM	Good combustion practices and natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	0.007lb/mmBtu when firing natural gas; 0.05 lb/mmBtu when firing fuel oil
PM_{10}	Good combustion practices and natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	0.007lb/mmBtu when firing natural gas; 0.05 lb/mmBtu when firing fuel oil
SO_2	Natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	0.0012lb/mmBtu when firing natural gas; 0.0032 lb/mmBtu when firing fuel oil
VOC See Note 2	Low NOx burners and good combustion practices	0.006lb/mmBtu when firing natural gas; 0.005 lb/mmBtu when firing fuel oil
Pb	Natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	
Hg	Natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	
HF	Natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	
H_2SO_4 mist	Natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	0.00024 lb/mmBtu when firing natural gas; 0.00064 lb/mmBtu when firing fuel oil

		See Note 1

Note 1: Based on an 30-day rolling average
Note 2: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table 7-13 lists WEPCO's proposed BACT and LAER for the expected IGCC auxiliary boiler emissions. This information is subject to change pending DNR's further review and analysis. A combination of low-NOx burners, good combustion practices, and use of natural gas or ultra-low-sulfur fuel oil are proposed. WEPCO has elected an operating limit of no more than 2,000 hours per year, of which no more than 500 hours per year is firing fuel oil.

Table 7-13 BACT and LAER For the auxiliary boiler for the IGCC boiler, based on WEPCO's permit application

Pollutant	Proposed Control Technology (BACT)	Proposed Limit (LAER)
CO	Low NO_x burners and good combustion practices	0.045 lb/mmBtu See Note 1
NOx	Low NO_x burners	0.05lb/mmBtu when firing natural gas; 0.09 lb/mmBtu when firing fuel oil *See Note 1*
PM	Good combustion practices and natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	0.007lb/mmBtu when firing natural gas; 0.02 lb/mmBtu when firing fuel oil
PM_{10}	Good combustion practices and natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	0.007lb/mmBtu when firing natural gas; 0.02 lb/mmBtu when firing fuel oil
SO_2	Natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	0.0012lb/mmBtu when firing natural gas; 0.0032 lb/mmBtu when firing fuel oil
VOC See Note 2	Low NO_x burners and good combustion practices	0.006lb/mmBtu when firing natural gas; 0.002 lb/mmBtu when firing fuel oil
Pb	Natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	
Hg	Natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	
HF	Natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	
H_2SO_4	Natural gas or ultra-low sulfur fuel oil with <0.003% sulfur	0.00024 lb/mmBtu when firing natural gas; 0.00064 lb/mmBtu when firing fuel oil See Note 1

Note 1: Based on an 30-day rolling average
Note 2: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table 7-14 lists the proposed BACT and LAER for the diesel generators at the plant. This information is subject to change pending DNR's further review and analysis. A combination of the latest diesel engine design, good combustion practices, and use of ultra-low-sulfur fuel oil are proposed.

Table 7-14 BACT and LAER for diesel generators, based on WEPCO's permit application

Pollutant	Proposed Control Technology (BACT)	Proposed Limit (LAER)
CO	New diesel engine design	41.2 lbs/hr See Note 1
NOx	New diesel engine design	6.9 g/hp-hr 33.4 lbs/hr See Note 1
PM	Fuel oil with <0.0003% sulfur	1.9 lbs/hr See Note 1
PM_{10}	Fuel oil with <0.0003% sulfur	1.9 lbs/hr See Note 1
SO_2	Fuel oil with <0.0003% sulfur	0.05 lb/hr See Note 1
VOC See Note 2	Good combustion practices	4.8 lbs/hr See Note 2
Pb	Fuel oil with <0.0003% sulfur	See Note 1
Hg	Fuel oil with <0.0003% sulfur	See Note 1
HF	Fuel oil with <0.0003% sulfur	See Note 1
H_2SO_4	Fuel oil with <0.0003% sulfur	See Note 1

Note 1: Operating limit of 500 hours per year

Table 7-15 lists the BACT and LAER proposals for the plant's three diesel fire pumps. This information is subject to change pending DNR's further review and analysis. The proposed BACT combines new diesel engine design and low-sulfur fuel oil with good combustion practices for VOC.

Table 7-15 BACT/LAER for diesel fire pump based on WEPCO's permit application

Pollutant	Proposed Control Technology (BACT)	Proposed Limit (LAER)
CO	New diesel engine design	3.4/hr See Note 1
NOx	New diesel engine design	14.0 lbs/hr See Note 1
PM	Fuel oil with <0.0003% sulfur	0.21 lb/hr See Note 1
PM_{10}	Fuel oil with <0.0003% sulfur	0.21 lb/hr See Note 1

Pollutant	Proposed Control Technology (BACT)	Proposed Limit (LAER)
SO_2	Fuel oil with <0.0003% sulfur	0.0055 lb/hr See Note 1
VOC *See Note 2*	Good combustion practices	0.31 lb/hr See Note 2
Pb	Fuel oil with <0.0003% sulfur	See Note 1
Hg	Fuel oil with <0.0003% sulfur	See Note 1
HF	Fuel oil with <0.0003% sulfur	See Note 1
H_2SO_4	Fuel oil with <0.0003% sulfur	See Note 1

Note 1: Operating limit of 500 hours per year
Note 2: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table 7-16 lists the proposed BACT and LAER for the IGCC combined cycle plant. This information is subject to change pending DNR's further review and analysis. The proposed BACT combines good combustion practices, diluent injection, the use of syngas, and gas clean-up.

Table 7-16 BACT/LAER for the IGCC combined cycle plant, based on WEPCO's permit application

Pollutant	Proposed Control Technology (BACT)	Proposed Limit (LAER)
CO	Good combustion practices	15 ppm; 0.030 lb/mmBtu
NOx	Diluent injection	15 ppm; 0.07 lb/mmbtu
PM	Good combustion practices, syngas fuel	23 lbs/hr; 0.011 lb/mmbtu
PM_{10}	Good combustion practices, syngas fuel	23 lbs/hr; 0.011 lb./mmbtu
SO_2SO2	IGCC process & gas cleanup	40 ppm sulfur in gasified fuel; 0.030 lb/mmBtu
VOC See Note 2	Good combustion practices	8.9 lbs/hr; 0.004 lb/mmBtu
Pb	Good combustion practices	26 lb/trillion Btu
H2SO4	IGCC & gas clean up	0.0005 lb/mmBtu
Hg	IGCC & gas clean up	0.6 lb/trillion Btu or 95% Removal

Note 1: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table 7-17 lists the proposed BACT for the different inactive coal pile handling emission sources. This information is subject to change pending DNR's further review and analysis. The proposed BACT combines wetting the material down, compacting it, and using telescoping chutes and covered conveyors.

Table 7-17 BACT/LAER for inactive coal storage piles based on WEPCO's permit application

Source Description	Proposed Control Technology (BACT)
Inactive coal pile A reclaim	Wet suppression
Inactive coal pile B reclaim	Wet suppression
Inactive coal pile A storage	Compaction and wet suppression or cover
Inactive coal pile B storage	Compaction and wet suppression or cover
Inactive coal pile A drop point	Covered conveyor, telescoping chute and wet suppressions
Inactive coal pile B drop point	Covered conveyor, telescoping chute and wet suppression

Table 7-18 lists the proposed BACT for the various potential emissions sources in the proposed gypsum handling system. This information is subject to change pending DNR's further review and analysis. WEPCO proposes a combination of tarp and water suppression, telescoping chutes, and covered conveyors. The gypsum wallboard plant is no longer being proposed for the Elm Road site.

Table 7-18 BACT/LAER for gypsum handling system, based on WEPCO's permit application

Source Description	Proposed Control Technology (BACT)
Gypsum dock-side storage pile	Tarp
Gypsum dockside pile drop point	Covered conveyor and telescoping chute
Gypsum barge loading drop point	Covered conveyor and telescoping chute
Gypsum barge loading activities	Supplemental wet suppression, as needed

Table 7-19 lists the proposed BACT for the various potential emission sources in the proposed limestone handling system. This information is subject to change pending DNR's further review and analysis. WEPCO proposes a combination of a partially-closed drop point, an enclosed hydraulic clamshell for unloading, a covered conveyor and telescoping chute, wetting, and a baghouse.

Table 7-19 BACT and LAER for limestone handling system, based on WEPCO's application

Source Description	Proposed Control Technology (BACT)
Continuous Screw unloader	Enclosed screw loader
Limestone storage pile drop point	Covered conveyor and telescoping chute
Limestone storage pile and reclaim	Wet suppression as required
Limestone prep building dust collector	Baghouse, 99% control efficiency, 0.004 gr/acf

~~Table 7-20 lists the proposed BACT for the various potential emission sources in the plant urea handling system. This information is subject to change pending DNR's further review and analysis. WEPCO's BACT would consist basically of using a vent filter for the urea exhaust fans.~~ Urea is no longer being proposed for the Elm Road site.

~~**Table 7-20 BACT and LAER for urea material handling point sources, based on WEPCO's permit application**~~

~~Source Description~~	~~Proposed Control Technology (BACT)~~
~~Urea silo exhaust fan~~	~~Vent filter, 99% control, 0.01 gr/acf~~
~~Urea storage bin No. 1 exhaust fan~~	~~Vent filter, 99% control, 0.01 gr/acf~~
~~Urea storage bin No. 2 exhaust fan~~	~~Vent filter, 99% control, 0.01 gr/acf~~
~~Urea storage bin No. 3 exhaust fan~~	~~Vent filter, 99% control, 0.01 gr/acf~~

Table 7-21 lists the potential coal materials handling emission sources in the ERGS project along with WEPCO's proposed BACT for each. This information is subject to change pending DNR's further review and analysis. The proposed BACT for each source would require the use of a baghouse.

Table 7-21 BACT and LAER for coal material handling point sources, based on WEPCO's permit application

Source Description	Proposed Control Technology (BACT)
Crusher house dust collector No. 1	Baghouse, 99% control, 0.004 gr/acf
Crusher house dust collector No. 2	Baghouse, 99% control, 0.004 gr/acf
Existing junction house 7/8 dust collector	Baghouse, 99% control, 0.004 gr/acf
Transfer tower No. 4 and tripper room Unit No. 1 DC	Baghouse, 99% control, 0.004 gr/acf
Tripper room dust collector Unit No. 2	Baghouse, 99% control, 0.004 gr/acf
Transfer tower No. 3 dust collector	Baghouse, 99% control, 0.004 gr/acf
Transfer house No. 5 dust collector	Baghouse, 99% control, 0.004 gr/acf
IGCC coal silos duct collector 1	Baghouse, 99% control, 0.004 gr/acf
IGCC coal silos dust collector 2	Baghouse, 99% control, 0.004 gr/acf
Coal ship unloading boom to hopper dust collector	Baghouse, 99% control, 0.004 gr/acf
Transfer house No. 6 dust collector	Baghouse, 99% control, 0.004 gr/acf
Transfer house No. 7 duct collector – alternate site only	Baghouse, 99% control, 0.004 gr/acf
Coal car dumper dust collector No. 1	Baghouse, 99% control, 0.004 gr/acf
Coal car dumper dust collector No. 2	Baghouse, 99% control, 0.004 gr/acf

Table 7-22 lists the potential coal materials handling emission sources in the ERGS project along with WEPCO's proposed BACT for each. This information is subject to change pending DNR's further review and analysis. BACT would be basically vent filters on the exhaust fans and a baghouse for the fly ash storage building.

Table 7-22 BACT and LAER for ash material handling point sources, based on WEPCO's permit application

Number	Source Description	Proposed Control technology
S27	Fly ash silo 1 exhaust fan	Vent filter, 99% control, 0.01 gr/acf
S65	Fly ash silo 2 exhaust fan	Vent filter, 99% control, 0.01 gr/acf

BACT ~~and LAER~~ for trucks on haul roads to and from the Caledonia landfill are also based on WEPCO's permit application at this point. This information is subject to change pending DNR's further review and analysis. BACT would involve the use of paved roads with new technology vacuum street sweepers as mitigative controls. The frequency of the vacuum street sweeping would be twice daily or whenever visible emissions from the haul roads are observed by trained personnel.

Air quality impacts - construction phase (p. 163)

In addition to long-term air quality impacts (as discussed above), short-term, temporary, air quality impacts of the project construction must be addressed. Air emissions from the project's construction phase would result primarily from:

- The use of construction equipment needed to clear, excavate, contour, and grade land
- Construction of the structures.
- Associated fuel combustion emissions from trucks and other equipment.

Fugitive particulate matter emissions would be expected from the site preparation activities and from the use of mobile equipment and vehicles. ~~The DNR's air pollution permit~~ NR 415 ~~would~~ establishes general fugitive dust control requirements. For example, the company must take precautions to prevent fugitive dust emissions during excavation.

Total suspended particulates (TSP) would constitute the major portion of the air emissions during the construction phase. Most of the TSP would be fugitive dust emissions from grading activities and from excavation, hauling, loading, and dumping. Emissions of SO2, NOx, and CO would result from construction equipment exhaust.

Wis. Admin. Code ch. NR 415 contains provisions for the control of fugitive dust. ~~The air permit would require the ERGS to minimize fugitive dust emissions during the construction~~. Applicable measures to control fugitive dust emissions would have to be used at the site. Potential dust resulting from construction activities and track traffic would have to be controlled by following what are considered standard practices during construction, such as watering of exposed surfaces, reduced speed limits on the site and limiting construction activities during high wind conditions.

Emissions generated during the construction phase would be expected to be limited to the site area and along the haul routes used to transport excavated soil to stockpile areas. Numerous earth-moving machines and dump trucks are expected to be operating up to 12-14 hours per day six days per week. Additional information is needed to determine the local air quality impacts related to the proposed ERGS excavation and soil stockpiling activities and facility construction.

Air quality impacts - plant operation (p. 163)

The expected air quality modeling results in Tables 7-23 through 7-30 in this section are values from WEPCO's air modeling analysis, which it performed for the North site, North site with accommodations, South site, and South site Exp. To assess pollutant-specific impacts, the maximum predicted impact for each air pollutant is added to the respective background ambient air concentrations to determine worst-case concentrations. These worst case compared to NAAQS. This information is summarized in Tables 7-23, 7-25, 7-27, and 7-29, for the North, North with accommodations and South Sites and the South Site-Exp, respectively. The last four lines in each table indicate the direction and distances of the greatest air pollution impact from the sources.

Air modeling is being performed at the DNR to determine the maximum predicted impact relative to the NAAQS and to the allowable PSD increments. The resulting DNR Air Pollution Control permit would establish the PSD baseline for the area. Comparison to the PSD increment are shown in Tables 7-24, 7-26, 7-28, and 7-30, for the North, North with accommodations and South Sites and the South South-Exp, respectively. These tables include cumulative impacts and cumulative percentages of increment consumed. The information in them is based on WEPCO's air pollution control permit application. The data is subject to change pending DNR's further review and analysis.

Lower stack heights for South Site and South Exp were necessary to satisfy the requirements of the Federal Aviation Administration that the stacks do not exceed obstruction standards and would not be a hazard to air navigation. An updated air quality modeling analyses was performed to reflect a new proposed stack height of 470 feet for the Super Critical Pulverized Coal Units. In addition, the short term SO_2 emission rate for each SCPC unit's was reduced to 1,150 lb/hr for South Site and 1,650 lb/hr for South Exp in order to meet the 24 hours PSD increment.

The local community has expressed concerns about the potential for fugitive dust emissions from the coal storage and handling areas in relation to the proximity to local residences. They have also commented regarding the height of the proposed stacks. WEPCo has reviewed the overall site layout and has developed an option that locates the coal storage and handling areas within the train rail loop. This layout also relocates the existing 138/345 KV substations to other areas on the plant site. If this option is adopted, the distance from the coal pile to the nearest resident would increase from 1,200 feet to approximately 2,800 feet. This would reduce the potential for off-site fugitive dust and would reduce the potential for noise associated with coal dozer operations. A power block design has been developed that would employ one five hundred fifty foot chimney rather than the two six hundred and seventy five foot stacks

Table 7-23 Air quality modeling results for the ERGS at the North Site

Pollutant	PM_{10} 24-hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO2 3- hour	SO2 24- hour	SO2 Annual	CO 1-hour

Pollutant	PM_{10} 24-hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO2 3- hour	SO2 24- hour	SO2 Annual	CO 1-hour
Maximum concentration (ug/m3)	65.99	7.98	72.26	0.00157	649.78	165.31	5.71	782.48
Background concentration (ug/m3)	58	27	76	NA	208.10	57.80	9.30	4,320
Total concentration (ug/m3)	123.99	34.98	148.26	0.00157	857.88	223.11	15.01	5,102.08
NAAQS standard (ug/m3)	150	50	150	1.5	1,300	365	80	40,000
Percent of NAAQS	82.6%	70.0%	98.8%	-	66.0%	61.1%	18.8%	13%
Impact distance in meters (m)								
Impact direction								
Impact UTM easting (m)	432,542	432,542	432,542	429,092	429,692	429,192	429,092	432,059
Impact UTM northing (m)	4,743,400	4,743,550	4,743,400	4,746,800	4,747,400	4,747,200	4,746,800	4,744,449

Table 7-23 shows that the modeled concentrations from the proposed ERGS and other NAAQS sources are below the standard level of pollution allowed for the region, although the concentration of TSP would come very close to 100 percent of the standard. As can be seen in Table 7-24, below, most of the expected increment would be consumed by the ERGS for 24-hour P_{M10} and 24-hour SO2 concentrations. Other pollutant concentrations would consume less of the increment.

Table 7-24 PSD increment modeling results for the ERGS at the North Site

Pollutant	PM_{10} 24 – Hour	PM_{10} Annual	NO_2 Annual	SO2 3 - hour	SO2 24 - hour	SO2 Annual
PSD Class II Increment Concentration (ug/m3)	30	17	25	512	91	20
Maximum Elm Road Project Only Concentration (ug/m3)	27.45	5.03		239.09	76.86	4.30
Percent of Class II Increment	91.5%	29.6%		46.7%	84.5%	21.5%
Maximum Cumulative Concentration (ug/m3)	27.45	5.03		239.09	76.86	4.30
Percent of Class II Increment	91.5%	29.6%		46.7%	84.5%	21.5%
Cumulative Impact Distance (m)						
Cumulative Impact Direction	SW	WSW		SW	NW	SW
Cumulative Impact UTM Easting (m)	431,084	431,426		430,292	429,792	431,792

Cumulative Impact UTM Northing (m)	4,744,086	4,743,201		4,742,950	4,746,700	4,742,900

Tables 7-25 and 7-26 shows that the modeled NAAQS and increment concentrations from the North Site with accommodations. The accommodations include locating the coal storage and handling areas within the rail loop and utilizing one five hundred and fifty foot chimney rather than two six hundred and seventy five foot stacks. In addition, the short term SO_2 emission rate for each SCPC unit's was reduced to 1,650 lb/hr in order to meet the 24 hours PSD increment. . The concentration of TSP would be a slightly lower percentage of the standard compared to the North Site without Accommodations, and less of the expected increment for the 24-hour PM10 and 24-hour SO2 increments would be consumed.

Table 7-25 Air quality modeling results for the ERGS at the North Site with Accommodations

Pollutant	PM_{10} 24-hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO2 3- hour	SO2 24- hour	SO2 Annual	CO 1- hour	NO2 Annual
Maximum concentration (ug/m3)	64.36	7.82	66.48	0.00	555.71	139.24	5.92	1,102.28	29.63
Background concentration (ug/m3)	58	27	76	NA	208.10	57.80	9.30	4,320	31
Total concentration (ug/m3)	122.36	34.82	142.48	0.00	763.81	197.04	15.22	5,421.88	60.63
NAAQS standard (ug/m3)	150	50	150	1.5	1,300	365	80	40,000	100
Percent of NAAQS	81.6%	69.6%	95.0%	-	58.8%	54.0%	19.0%	14%	60.6%
Impact distance in meters (m)									
Impact direction									
Impact UTM easting (m)	432,542	432,542	432,542	429,092	429,692	429,192	429,192	432,208	432,542
Impact UTM northing (m)	4,743,400	4,743,550	4,743,400	4,746,800	4,747,400	4,747,200	4,746,800	4,744,264	4,743,550

Table 7-26 PSD increment modeling results for the ERGS at the North Site with Accommodation

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	NO_2 Annual	SO2 3 - hour	SO2 24 - hour	SO2 Annual
	30	17	25	512	91	20

PSD Class II Increment Concentration (ug/m3)						
Maximum Elm Road Project Only Concentration (ug/m3)	25.03	5.40	1.30	228.56	69.34	5.20
Percent of Class II Increment	83.4%	31.8%	5.20%	44.6%	76.2%	26.0%
Maximum Cumulative Concentration (ug/m3)	25.03	5.40	1.30	228.56	69.34	5.20
Percent of Class II Increment	83.4%	31.8%	5.20%	44.6%	76.2%	26.0%
Cumulative Impact Distance (m)						
Cumulative Impact Direction	SW	WSW		SW	NW	SW
Cumulative Impact UTM Easting (m)	431,426	431,426	432,792	431,046	431,281	431,099
Cumulative Impact UTM Northing (m)	4,743,201	4,743,201	4,744,750	4,744,300	4,743,574	4,744,174

Tables 7-27 through 7-30 shows that the modeled NAAQS and increment concentrations from the South Site and South Site-Exp with stack height of 470 feet for the Super Critical Pulverized Coal Units. In addition, the short term SO_2 emission rate for each SCPC unit's was reduced to 1,150 lb/hr for South Site and 1,650 lb/hr for South Exp in order to meet the 24 hours PSD increment.

Table 7-27 Air quality modeling results for the ERGS at the South Site

Pollutant	PM_{10} 24-hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO2 3-hour	SO2 24-hour	SO2 Annual	NO_2 Annual
Maximum Concentration (ug/m3)	61.96	8.06	73.71	0.0030	730.11	178.48	12.80	28.52
Background Concentration (ug/m3)	58	27	76	NA	208.10	57.80	9.30	31.00
Total Concentration (ug/m3)	119.96	35.06	149.71	0.0030	938.21	236.28	22.10	59.52
NAAQS Standard (ug/m3)	150	50	150	1.5	1,300	365	80	100
Percent of NAAQS	80.0%	70.1%	99.8%	-	72.2%	64.7 %	27.6%	59.5%
Impact Distance in Meters (m)								
Impact Direction	SE	SE	WNW	N	N	N	N	SE
Impact UTM Easting (m)	432,495	432,495	431,191	432,342	432,342	432,292	432,292	432,495
Impact UTM Northing (m)	4,743,421	4,743,421	4,743.808	4,744,500	4,744,450	4,744,450	4,744,550	4,743,421

Table 7-28 PSD increment modeling results for the ERGS at the South Site

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	NO_2 Annual	SO2 3 - hour	SO2 24 - hour	SO2 Annual
PSD Class II Increment Concentration (ug/m3)	30	17	25	512	91	20
Maximum Elm Road Project Only Concentration (ug/m3)	29.61	5.64	2.72	185.20	85.21	6.09
Percent of Class II Increment	98.7%	33.2%	10.9%	36.2%	93.6%	30.4%
Maximum Cumulative Concentration (ug/m3)	29.61	5.64	2.72	185.20	85.21	6.09
Percent (%) of Class II Increment	98.7%	33.2%	10.9%	36.2%	93.6%	30.4%
Cumulative Impact Distance (m)						
Cumulative Impact Direction	SW	SW	SE	SW	W	W
Cumulative Impact UTM Easting (m)	431,174	431,426	432,842	431,041	431,980	433,192
Cumulative Impact UTM Northing (m)	4,742,590	4,743,201	4,742,900	4,742,594	4,742,926	4,743,750

Table 7-29 and Table 7-30 show similar air quality modeling results for the ERGS if it is located at the South Site-Exp.

Table 7-29 Air quality modeling results for the ERGS at the South Site-Exp

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO2 3 - hour	SO2 24 - hour	SO2 Annual	NO_2 Annual
Maximum Concentration (ug/m3)	61.97	7.98	73.77	0.0030	732.00	180.98	12.93	28.47
Background Concentration (ug/m3)	58	27	76	NA	208.10	57.80	9.30	31
Total Concentration (ug/m3)	119.97	34.98	149.77	0.0030	940.10	238.78	22.23	59.47
NAAQS Standard (ug/m3)	150	50	150	1.5	1,300	365	80	100
Percent of NAAQS	80.0%	70.0%	99.8%	-	72.3%	65.4%	27.8%	59.5%
Impact Distance in meters (m)								
Impact Direction	SE	SE	WNW	N	N	N	N	SE
Impact UTM Easting (m)	432,495	432,495	431,191	432,342	432,342	432,292	432,292	432,495
Impact UTM Northing (m)	4,743,421	4,743,421	4,743,808	4,744,500	4,744,450	4,744,450	4,744,550	4,743,421

Table 7-30 PSD increment modeling results for the ERGS at the South Site-Exp

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	NO_2 Annual	SO2 3 – hour	SO2 24 - hour	SO2 Annual
PSD Class II Increment Concentration (ug/m3)	30	17	25	512	91	20
Maximum Elm Road Project Only Concentration (ug/m3)	29.73	5.66	2.91	276.76	89.92	6.24
Percent (%) of Class II Increment	99.1%	33.3%	11.6%	54.0%	98.8%	31.2%
Maximum Cumulative Concentration (ug/m3)	29.73	5.66	2.91	276.76	89.92	6.24
Percent (%) of Class II Increment	99.1%	33.3%	11.6%	54.0%	98.8%	31.2%
Cumulative Impact Distance (m)						
Cumulative Impact Direction	SW	SW	SE	SW	W	WSW
Cumulative Impact UTM Easting (m)	431,174	431,426	432,842	430,992	431,192	433,192
Cumulative Impact UTM Northing (m)	4,742,590	4,743,201	4,742,850	4,742,100	4,742,100	4,743,750

Tables 7-27 and 7-29 show that the proposed ERGS at either of the South Site configurations and other NAAQS sources are below the ambient air quality standards, although the 24-hour concentration of TSP would come very close to 100 percent of the standard. As can be seen by comparing Tables 7-24 and 7-26 with Tables 7-28 and 7-30, more of the increment would be consumed by the ERGS for 24-hour P_{M10} and 24-hour SO2 concentrations than for either of the North Site configurations. Other modeled concentrations would consume less of the increments for the other pollutants.

The air modeling and PSD increment results demonstrates that ERGS meets the NAAQS and PSD increment. The preliminary determination is that the ERGS project qualifies for a permit. A final determination will made after the requirements of Wis. Admin. Code ch. NR 150, the DNR WEPA rule, are satisfied.

Additional impacts analysis (p. 167)

The following section summarizes results of the additional impacts analyses performed for the DNR by WEPCo. These results remain to be confirmed by the DNR analyses.

PSD Increment Impacts [new}

Increment impacts are very localized at specific locations around the plant site and are not regional in nature. Ambient air quality modeling results indicate that the amount of increment consumed by the Elm Road Generating Station will drop to less than 50 % of the

PSD standard within 800 yards of the plant site. The probability that a new PM10 source would impact the same specific locations at the Elm Road site is very remote. For example, a modeling analysis was performed to determine if a new PM10 source could be located within Racine County. The modeling analysis assumed that the current largest particulate matter emitter in Racine county is located as a new source in the Caledonia Business Park which is approximately 4 miles from the Elm Road site. This is a conservation assumption since any significant new source of particulate matter would need to install best available controls as part of the permit process. The PSD increment modeling results show that this new source would not have a measurable impact on the specific high increment locations around the Elm Road site. Therefore, the Elm Road Generating Station would not affect this new source or any other major source of PM from being able to obtain an air permit.

The Multi-Emission Reduction Agreements. [new]

PTF proposes to invest about $1.3 billion in *existing* power plants within the We Energies system in order to improve efficiency and reduce emissions. To implement this portion of the PTF energy plan, We Energies has entered into two agreements that will adopt an integrated multi-emission approach to reduce emissions at its coal burring power plants in Wisconsin and Michigan. Cost estimates associated with implementing the emission controls required by these agreements are part of the overall PTF energy plan.

On September 30, 2002, We Energies entered in a voluntary Multi-Emission Cooperative Agreement (MECA) with the Wisconsin Department of Natural Resources (WDNR). The agreement commits We Energies to reducing SO2, NOx, and mercury emissions from the Wisconsin coal fired power plants over the next ten years. The MECA calls for system wide annual and ozone seasonal NOx emissions to be reduced by 60% to 65%, annual SO_2 emissions to be reduced by 45% to 50% and annual mercury emissions to be reduced by 50%.

In addition, on April 29, 2003, We Energies entered a settlement agreement with the U.S. Department of Justice and the U.S. Environmental Protection Agency (EPA) that commits to further reductions in SO2 and NOx over the next ten years. The agreement sets mandatory 12 month rolling system wide mass and rate emission limits for five coal fired power plants located in Wisconsin and Michigan. The plants covered under the agreement are Pleasant Prairie, Oak Creek Valley, Port Washington in Wisconsin and Presque Isle located in Michigan.

The settlement agreement will result in a 68% to 73% reduction in annual system-wide reductions in NOx emissions, and a 66% to 71% reduction in system-wide SO2 emissions. In addition, specific SO2 and NOx pollution control equipment approved by EPA must be installed by dates certain. SO2 scrubbers and selective catalytic reduction (SCR) equipment must be installed on Pleasant Prairie Units 1 and 2 by 2008, and on Oak Creek Unit 7 and 8 by 2013. For Oak Creek Units 5 and 6, and Presque Isle Units 1 through 4, pollution controls must be installed or the units retired, also by 2013. The specific 12 month rolling systemwide mass and rate emission limits that must be met by 2013 are summarized below:

	System-wide 12 Month Rolling Average Emission Rate, lbs/mmBtu	System-wide 12 Month Rolling Tonnage Limit, tons
SO2	0.32	33,300
NOx	0.170	17,400

The settlement agreement with EPA incorporates the NOx and SO2 provisions of the MECA. The settlement agreement also incorporates a recent emissions-related agreement that was reached with the City of Oak Creek as part of the on-going discussions with the local community about adding the new Elm Road coal units to the existing Oak Creek site. If one or more of the new units at the proposed Elm Road Generating Station is approved and constructed, Wisconsin Electric is required to limit the combined emissions of SO_2, NO_x, PM, mercury, VOCs, hydrochloric acid, hydrofluoric acid, and sulfuric acid from both its South Oak Creek Generating Station and its Elm Road Generating Station to 38,400 tons per year, collectively. Compliance with this emission limitation is to be demonstrated on a 12-month rolling average. This emission cap will be incorporated into a single Title V air operating permit for the combined ERGS – Oak Creek facility. DNR will revise the current operating permit for the existing units to include the new ERGS units prior to the ERGS construction permit expiring.

Ozone and PM2.5 Impact Assessment [new, to be transmitted under separate cover]

Scientists at Alpine Geophysics and ENVIRON conducted state-of-the-science regional air quality modeling to assess the potential incremental impacts of PTF as well as the multi-emission reduction agreements on regional ozone (1-hr and 8-hr) and fine particulate (24-hr PM2.5 and PM10) standards. Alpine Geophysics and ENVIRON are recognized as leaders in the field of regional modeling and have conducted similar modeling for the Lake Michigan Air Directors Consortium (LADCO) and the Midwest Regional Planning Organization (MRPO).

The modeling was conducted using data from 57 day period during the summer of 2001. The model was set up to reconstruct the environmental setting that existed during this well-documented period in 2001. Alpine Geophysics and ENVIRON have concluded the following related to the possible impacts on ozone levels in the region:

- Addition of the proposed new ERGS units by themselves, without the planned NOx reductions from the existing WEPCo facilities, would have minimal impacts on the regional 1 hour and 8 hour ozone concentrations, less than 1 ppb increases. ;
- When adding in the emission reductions associated with the multi-emission agreements with DNR and with EPA , there would also be minimal impacts to regional ozone concentrations, The increases and decrease in the 8-hour ozone concentrations are generally less than 1 ppb.
- In some isolated instances, PTF emission reduction measures produced small, less than 2 ppb increases in 8-hour ozone concentrations. These increases occur in isolated onshore areas, but they mostly occur over Lake Michigan away from population centers.

This last result may at first seem somewhat confusing. For example, we are seeing slight increases in ozone levels in some areas in spite of he fact that we are reducing NOx emissions from generating facilities in Oak Creek. However, the modeling results actually reflect the well established fact that large point source NOx plumes actually "consume" atmospheric ozone in areas close to these sources.

For 24-hr $PM_{2.5}$, Alpine Geophysics and ENVIRON have concluded the following:

- Addition of the proposed new ERGS units by themselves, without the planned NOx reductions from the existing WEPCo facilities, has minimal impacts on 24-hr $PM_{2.5}$ concentrations in the region.
- The modeling results indicate that when the occasional incremental increases occur, they are typically less than 0.5 µg/m ^{3} and primarily occur over Lake Michigan By contrast, when the PM2.5 analysis predicts concentration decreases to occur, the decreased concentration levels are on the order of 1 to 3 µg/m^3.

With respect to future predictions of PM, it should be noted that the "state of the PM modeling science" is not as well developed as is the case for ozone modeling. For example, the model significantly "under-predicts" PM levels in some portions of the Milwaukee-Chicago region With this caveat in mind, the modeling indicates the proposed project does not result in any new exceedance days for either ozone or PM as compared to the base case scenario.

These results strongly suggest that the proposed PTF will not negatively impact regional ozone or PM concentrations.

MERCURY DEPOSITION <u>[new, to be transmitted under separate cover]</u>

Scientists at Atmospheric & Environmental Research, Inc. employed the Total Risk of Utility Emissions (TRUE) model to assess the potential impact of the new Elm Road and existing Oak Creek units on local mercury deposition in Wisconsin. The TRUE model includes a state-of-the-science module to simulate the atmospheric transformations, transport and deposition of the elemental and oxidized forms of mercury.

TRUE simulations were conducted for each of the four units at Oak Creek as well as for the three proposed ERGS units to determine their contribution to wet and dry deposition of mercury within 100 km (~ 60 mi.) of the source.

The maximum simulated annual incremental mercury deposition due to the new ERGS units is 0.24 µg/m^2-y . The corresponding maximum annual mercury deposition <u>attributable to</u> the existing Oak Creek Power Plant is 0.51 µg/m^2-y. The maximum total deposition due to each plant occurs within 10 km, east of the plant (winds flow primarily from west to east in this region).

Using data from the Lake Geneva MDN station, the existing Oak Creek units were estimated to contribute approximately 2% to the current~~e about 2%(?)of the~~ total background Hg deposition in this region. The new ERGS could increase local background Hg deposition by about 1%. These estimates are considered "worst case" for two reasons:

- contemporary mercury emission rates were used in this exercise, in spite of the fact that mercury emissions from existing units will be reduced via additional SO_2 and NOx control measures by 2010 per the EPA settlement agreement;
- the existing model does not address recent field and laboratory findings regarding oxidized mercury conversion to the elemental form in coal-fired utility boiler plumes
- reductions required by pending new state mercury rules were not considered

Finally, it must be acknowledged that, based on years of research funded by EPRI and others in Wisconsin via projects managed by DNR, mercury deposition onto the surface of Lake Michigan does not likely lead to enhanced mercury uptake by the food chain due to the water chemistry properties of Lake Michigan In this case, oxidized mercury is not converted to the more toxic methylmercury form in Lake Michigan because the microorganisms that convert mercury are absent in well-oxygenated lake systems. In addition, the pH of Lake Michigan fosters reaction pathways that convert oxidized mercury to elemental mercury in the water column. This converted mercury is then released to the atmosphere.

Lake Michigan Shoreline Impacts [new, to be transmitted under separate cover]

Scientists at ENSR International (ENSR) conducted a state-of–the-art air quality dispersion modeling analysis to assess the potential impact of the proposed Elm Road Generating Station (ERGS) units and the existing South Oak Creek Power Plant (OCPP) generating units on the short-term national ambient air quality standards for sulfur dioxide (SO_2 – 3-hour and 24-hour periods), inhalable particulate matter (PM_{10} – 24-hour period) and carbon monoxide (CO – 1-hour and 8-hour periods) and short-term PSD Class II increments for SO_2 (3-hour and 24-hour periods) and PM_{10} (24-hour period). The short-term (1-hour to 24-hour) averaging periods were focused on in this analysis because shoreline fumigation (lake breeze) events typically occur over a relatively short time period (several hours) within a given day under special meteorological conditions. The modeling analysis was also conducted to determine whether shoreline fumigation would cause higher predicted ground-level concentrations than the conditions associated with traditional overland dispersion.

The modeling analysis was conducted using the EPA's Shoreline Dispersion Model (SDM) to evaluate shoreline fumigation impacts and EPA's Industrial Source Complex Short Term (ISCST3) model to address traditional overland dispersion impacts in order to compare modeled impacts with and without shoreline fumigation. The modeling analysis used stack and emissions input data that were used in the ISCST3 modeling analysis that supported the air construction permit application for the proposed ERGS project, including the existing OCPP generating units. The modeling analysis used 1982-1986 Milwaukee surface and Green Bay upper air meteorological data which is the standard meteorological input database recommended by Wisconsin DNR. Model receptors were placed out to 20 kilometers from the proposed project location with sufficient receptor grid resolution in order to assure that the peak modeled impacts were captured. Furthermore, the receptor grid was supplemented with discrete property fence line receptors spaced at 100 meters. Modeled peak concentration receptors were further evaluated using a 100-meter receptor grid resolution within the vicinity of the peak modeled receptors to determine the worst-case peak air quality impacts for each applicable pollutant and averaging period.

The results of the modeling analysis indicate that the proposed project point source emissions, in conjunction with the existing plant emissions and regional background concentrations, will not cause or contribute to an exceedance of the short-term ambient air quality standards for SO_2, PM_{10} and CO. Furthermore, the modeling analysis results indicate that the air quality impacts for PSD increment consuming sources (proposed ERGS sources) will not cause or contribute to an exceedance of the PSD Class II increments for SO_2 and PM_{10}. The modeling results also indicate that the ISCST3 model shows higher ground-level concentrations than the SDM model and that shoreline fumigation effects are not a critical factor in causing peak ground-level concentrations in the vicinity of the proposed ERGS project site.

Visibility impact
PM, NOx, and SO2 emissions from power plant may have the potential to impact local and regional visibility. NOx, and SO2 emissions react in the atmosphere to form sulfate and nitrate compounds. These compounds condense as very fine particulate matter and can cause visibility impairment.

However, nitrate and sulfate deposition are air pollution regional or long-range transport issues. The potential emissions of these pollutants from the ERGS would be a small fraction of the annual statewide emissions as discussed below. As a result, the ERGS is not expected to cause any perceptible visibility impacts to the region. In addition, a Level I screening analysis indicates that the maximum visual impacts to the nearest Class I wilderness areas, the Rainbow Lake and Seney Wilderness areas in northwest Wisconsin, would be less than the screening criteria and thus constitute no significant visual impact.

Particulate matter (p. 168)
Both the SCPC and IGCC units would be subject to Wis. Admin. Code § NR 415.06 and have an allowable PM emission rate of 0.1 lb/mmBtu, for fuel burning sources that have a heat input of greater than 250 mmBtu/hr and emit PM. The maximum particulate emissions from the SCPC units would be 0.018 lb/mmBtu, and the maximum emissions from the IGCC CTs would be 0.011 lb/mmBtu (based on the air permit application's maximum of 22.8 lb/hour and 2,139 mmBtu/hr on syngas). Therefore, the SCPC units and the IGCC would be in compliance with this standard.

State requirements (p. 168)

Opacity
It appears that the two SCPC units and the IGCC unit would meet this requirement under Wis. Admin. Code ch. NR 431.

Impacts to soils and vegetation

Impacts to soil would result from deposition and incorporation of pollutants into the soil so that soil
characteristics are changed and the soil or plant life are affected. Impacts to vegetation could also be more direct, resulting from deposition of pollutants onto the plants themselves or absorption of soil pollutants by the plant roots.

The primary pollutants in this case would be NOx, CO, SO2, and PM. In addition, this power plant would be a source of hazardous air pollutants, including ammonia, mercury, and other trace elements that occur in coal and limestone. The emissions and potential concentrations of hazardous air pollutants from the project are discussed below in more detail.

Emissions from the ERGS units could cause increases in nitrate (NO3-) and sulfate (SO4-) ion deposition to soils and vegetation in the area. However, as discussed above with respect to visibility impairment, nitrate and sulfate deposition rates are regional or long range transport air pollution issues. NOx and SO2 emissions are normally transported tens to hundreds of miles before deposition occurs. As a result, the proposed project is not expected to affect area nitrate or sulfate deposition rates significantly.

The national ambient air quality standards include public health and welfare standards intended to protect soils and vegetation from significant air pollution impacts. The ambient air quality analysis for the ERGS demonstrate compliance with the NAAQS and PSD increment requirements, significant deposition impacts would not be expected. If the plant operated at 100 percent capacity and all of its emissions were deposited uniformly in an area surrounding it within a radius of 200 miles, the nitrate and sulfate deposition rates would represent a small percentage increase in nitrate and sulfate deposition. Actual impacts are expected to be very small.

Acid deposition emissions (p. 169)

SO2 emissions

The potential SO2 emissions from this power plant, based on the worst-case fuel and the operation of the plant at its maximum capacity for 8,760 hours per year, are shown in Table 7-9 as 9,785 tons per year. For facilities of this type, normal operation is typically 75 to 90 percent of this maximum capacity. For comparison, the total Wisconsin utility emissions and total Wisconsin annual emissions can be summarized as follows:

ERGS 9,785 tpy
Wisconsin major utilities combined 211,522 tpy
Total Wisconsin emissions 303,049 tpy

The total Wisconsin SO2 emission of 303,049 tons is down 56 percent from the l980 level of 686,399 tons. As illustrated, the potential annual SO2 emissions would be less than one-half of one percent of the annual actual emissions from all Wisconsin utilities combined. The expected ERGS emissions would, however, represent new SO2 emitted into the Wisconsin atmosphere.

NOx emissions

The total potential NOx emissions expected from this power plant amount to about 5,245 tons per year, as shown in Table 7-9, again based on the worst case scenario. Normal plant operations would emit less. For comparison, the total Wisconsin utility emissions and total Wisconsin annual emissions can be summarized as follows:

ERGS 5,245 tpy
Wisconsin major utilities combined 116,538 tpy
Total Wisconsin emissions 193,795 tpy

Again, the potential annual NO, emissions from this power plant are less than half of one percent of the annual actual emissions from all Wisconsin utilities combined. However, the expected ERGS emissions would represent new NOx emitted into the Wisconsin atmosphere.

Federal Acid Rain Program

The ERGS would be an affected new unit under the federal Acid Rain Program in 40 CFR Part 72 - 76. In order to operate, the ERGS would be required to buy allowances from another power plant that has reduced its emissions below the allowances allocated. Even though the ERGS would be a modification of an existing major stationary source, the total U.S. emissions are capped, so that the ERGS cannot add new SO2 emissions beyond the cap.

Greenhouse gas emissions (p. 170)

The primary greenhouse gas from the ERGS units would be CO2. N20 would also be emitted from this project. The global warming potential for these emissions can be expressed as equivalent tons of CO2 emissions.79

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79 Nitrous oxide absorbs about 270 times more heat than carbon dioxide. Emissions of nitrous oxide are expected to be less than 10 percent of total NOx emissions, or about 33 tons per year. This is equal to CO2 equivalent emissions of 8,600 tons per year.

The total potential CO2 equivalent emissions from the ERGS would be 1,060,000 tons per year. This
estimate is based on the worst-case fuel (bituminous coal) and the operation of the power plant at its
maximum capacity for 8,760 hours per year. For facilities of this type, normal operation is typically 75 to 90 percent of this maximum potential capacity. For comparison, the total Wisconsin utility emissions, Wisconsin transportation emissions, and total Wisconsin annual emissions can be summarized as follows:

ERGS 1,060,000 tpy
Wisconsin major utilities 80 54,170,000 tpy
Wisconsin highway and non-highway

transportation 45,300,000 tpy
Total Wisconsin emissions 154,400,000 tpy

From this data, it can be seen that the potential annual CO2 emissions from the ERGS would be about 1.9 percent of the annual actual emissions from all Wisconsin utilities combined, and about 0.7 percent of total statewide CO2 emissions. The potential increase in greenhouse gas emissions from this project is relatively small compared with actual statewide emissions, but it still represents additional CO2 emitted into the Wisconsin atmosphere.

Hazardous air pollutants (p. 170)

The primary fuel for the ERGS generation boilers would be a blend of 95 percent washed bituminous coal and 5 percent coal ash (on a weight basis). A variety of fuel ashes have been analyzed. The analyses demonstrate that the fuel ash meets the definition of lignite coal as found in Wis. Admin. Code § NR 400.02 (22e). For this reason, the fuel ash is exempt from review under the hazardous air pollutant rule, Wis. Admin. Code ch. NR 445.

The emissions of HAPs from the combustion of natural gas and fuel oil are also exempt from NR 445 requirements because these fuels are considered virgin fossil fuel.

The case of mercury
Hg emissions from the ERGS would occur as a result of trace amounts of this element coming from the coal and limestone. Of all the inorganic HAPs on the federal HAPs list, Hg is generally present in limestone and coal at the lowest levels. However, as shown in Table 7-33, total Hg emissions would be over 300 lbs/yr. Based on this table, Hg emissions are also subject to the PSD program
under Wis. Admin. Code ch. NR 405.

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80 Data for the Wisconsin utilities and statewide emissions were taken from the DNR publication Wisconsin Greenhouse Gas Emission Reduction Cost Study, PUB-AM-186 95.

HAPs emissions estimates (p. 171)

The Tables 7-29, 7-30, 7-31, and 7-32 summarize the HAPs emissions expected from the different emission sources. These emissions levels are based on WEPCO's calculations in its air permit application. This data is subject to change pending DNR's further review and analysis.

Table 7-29 shows HAPs emitted by each of the SCPC units. These units would be burning bituminous coal.

Table 7-29 Hazardous air pollutants emissions for each SCPC coal-fired boiler in lbs/hour and tons per year

Pollutant	Lbs/hr	TPY
Antimony	0.021	0.091
Arsenic	0.037	0.16
Beryllium	0.0020	0.0087
Cadmium	0.0068	0.03
Chlorine (as HCL)	15.8	69.4
Chromium	0.055	0.24
Cobalt	0.0087	0.038
Fluorine	5.46	23.9
Lead	0.046	0.20
Manganese	0.076	0.33
Mercury	0.014	0.06
Nickel	0.052	0.23
Selenium	0.30	1.33
Formaldehyde	0.0297	0.130
Other organic HAPs	0.0004	0.002

The SCPC auxiliary boiler would burn either natural gas or diesel fuel oil. For the SCPC boiler island
auxiliary boiler, WEPCO has elected to limit firing natural gas to 1,500 hours per year and fuel oil to 500 hours per year. The HAPs emissions expected from this boiler are shown in Table 7-30.

Table 7-30 Hazardous air pollutants emissions for SCPC boiler island auxiliary boiler

Pollutant	Lbs/hr	TPY
Lead	0.0022	0.0006
Mercury	0.0007	0.0002
Beryllium	0.0007	0.0002
Fluorides	-	-
Sulfuric acid mist	0.14	0.08
Formaldehyde	0.06	0.03
Other organic HAPs	0.06	0.01

The IGCC auxiliary boiler would burn either natural gas or diesel fuel oil. For the IGCC boiler island auxiliary boiler, WEPCO has elected to limit firing natural gas to 1,500 hours per year and fuel oil to 500 hours per year. The HAPs emissions expected from this boiler are shown in Table 7-31.

Table 7-31 Hazardous air pollutants emissions for IGCC boiler island auxiliary boiler

Pollutant	Lbs/hr	TPY
Lead	0.0009	0.0002
Mercury	0.0003	0.0001
Beryllium	0.0003	0.0001
Fluorides	-	-
Sulfuric Acid Mist	0.05	0.03
Formaldehyde	0.02	0.01
Other organic HAPs	0.02	0.01

The IGCC unit would gasify bituminous coal and burn the syngas that is produced. The HAPs emissions from this unit are shown in Table 7-32.

Table 7-32 Hazardous air pollutants emissions for IGCC unit

Pollutant	Lbs/hr	TPY
Antimony	0.005	0.02
Arsenic	0.01	0.49
Beryllium	0.006	0.03
Cadmium	0.005	0.02
Chlorine (as HCL)	0.67	2.95
Chromium	0.07	0.31
Cobalt	0.03	0.12
Fluorine	0.12	0.52
Lead	0.11	0.50
Manganese	0.13	0.59
Mercury	0.007	0.03
Nickel	0.08	0.33
Selenium	0.06	0.25
Formaldehyde	0.33	1.40
Organic HAPs	0.06	0.26

The associated equipment that would produce sulfuric acid as a by-product of the IGCC operation is anticipated to emit the criteria pollutant emissions of nitrogen oxides, sulfur dioxide and sulfuric acid mist.

Table 7-33 provides a summary of the estimated potential emissions of hazardous air pollutants from major emissions sources in the ERGS. It does not include fugitive coal dust and other dust, which should be low if appropriate controls are implemented. These estimated emissions are based on WEPCO's calculations in its air permit application. This data is subject to change pending DNR's further review and analysis.

Table 7-33 Hazardous air pollutants emissions from the major components of the ERGS in tons per year

Hazardous Air Pollutant	SCPC Unit 1	SCPC Unit 2	IGCC	SCPC Auxiliary Boiler	Diesel Genera tor	Fire Pump	IGCC Auxiliary Boiler
Antimony	0.091	0.091	0.021	negligible	negligible	negligible	negligible
Arsenic	0.164	0.164	0.490	negligible	negligible	negligible	negligible
Beryllium	0.009	0.009	0.025	negligible	negligible	negligible	negligible
Cadmium	0.030	0.030	0.018	negligible	negligible	negligible	negligible
Chromium	0.239	0.239	0.310	negligible	negligible	negligible	negligible
Cobalt	0.038	0.038	0.119	negligible	negligible	negligible	negligible
Lead	0.202	0.202	0.501	0.001	negligible	negligible	negligible
Manganese	0.332	0.332	0.585	negligible	negligible	negligible	negligible
Mercury	0.962	0.962	0.029	0.0002	negligible	negligible	0.0001
Nickel	0.226	0.226	0.334	0.001	negligible	negligible	negligible
Selenium	1.328	1.328	0.254	0.001	negligible	negligible	negligible
Hydrogen Chloride	69.360	69.360	2.946	negligible	negligible	negligible	negligible
Hydrogen Fluoride	23.930	23.930	0.520	negligible	negligible	negligible	negligible
Formaldehyde	0.130	0.130	2.886	0.014	negligible	negligible	negligible
Totals	97.041	97.041	9.038	0.017	---	---	---

Table 7-33 shows that the total potential emissions of Section 112 HAPs from the ERGS are estimated at about 203 tpy. The provisions in 40 CFR Sec 63.41 define constructing a major source to mean installing at any developed site a new process or production unit which in and of itself emits or has the potential to emit 10 tons per year of any individual HAP or 25 tons per year of any combination of any HAPs. Thus, the proposed ERGS project is subject to case-by-case MACT requirements for HAPs.

Table 7-34 summarizes the case-by-case MACT proposed by WEPCO. The HAPs are aggregated into different types depending on their chemistry: inorganic solid HAPs, inorganic acid HAPs, organic HAPs, and mercury. The information in the table below is based on WEPCO's air permit application information. The data is subject to change pending DNR's further review and analysis.

Table 7-34 Case-by-case MACT for ERGS HAPs emission sources and their HAPs

Type of Pollutants	Proposed MACT				
	SCPC Boilers	IGCC Unit	Diesel Engine	Fire Pump	Aux. Boilers
Inorganic Solid HAPs	Complying with the PM emission limit	Syngas cleanup operation and good combustion practices for the CT	Use of fuel oil and complying with the PM BACT limits	Use of fuel oil and complying with the PM BACT limits	Use of natural gas and fuel oil and complying with the PM BACT limits
Inorganic Acid HAPs	Complying with and meeting the SO2 emission limit	Syngas cleanup operation and good combustion practices for the CT	Use of fuel oil	Use of fuel oil	Use of natural gas and fuel oil
Organic HAPs	Complying with and meeting the VOC emission limit	IGCC process and good combustion practices for the CT	Complying with and meeting the VOC emission limit	Complying with and meeting the VOC emission limit	Complying with and meeting the VOC emission limit
Mercury	Multi-pollution controls	Use of carbon bed filter or filters containing other similar material in the syngas, or a removal of 90% achieved without carbon filtration, or other requirements for effective control of mercury as promulgated by the EPA	Use of fuel oil and complying with or meeting PM emission limit	Use of fuel oil and complying with or meeting PM emission limit	Use of natural gas and fuel oil and complying with meeting PM emission limit

Ammonia under NR 445 (p. 174)

Ammonia emissions are expected from the use of SCR at the SCPC boilers. Ammonia is regulated under Table 1 of Wis. Admin. Code ch. NR 445. For ammonia, compliance with an acceptable ambient air concentration established by rule is required.

The proposed ammonia emission limit from the SCPC units is 5 ppm, which is equivalent to 20 lb/hour from each SCPC stack. The threshold value for ammonia from stacks in excess of 25 feet, according to Table 1 of Wis. Admin. Code ch. NR 445 is 6.28 lb/hr. Since the SCPC boilers may emit ammonia in excess of the table value, NR 445 requires that dispersion modeling be performed to demonstrate that the maximum ambient concentrations of ammonia do not exceed 2.4 percent of the threshold limit value (TLV) established by the American Conference of Governmental and Industrial Hygienists (ACGIH).

The ACGIH, 2001 standards list a TLV of 25 ppm for ammonia. This is equal to 17,678 ug/m 3 . Ten percent (1 hour value) of this TLV would be 1,767 ug/m 3 , and 2.4 percent (24 hour value) of the TLV would be 424 ug/m 3 .

WEPCO's modeling shows that the maximum hourly-modeled impact would be 4.37 ug/m 3 , that the 24-hour modeled impact would be 0.36 ug/m 3 , and that the annual impact would be 0.013 ug/m 3 . This WEPCO information in the air permit application is subject to change depending on the DNR's review and analysis. Based on these modeling results, ERGS would meet the ambient air standards required under NR 445 for ammonia.

Chapter Summary (p. 175)

- Each component of the plant that has the potential for producing emissions has been analyzed to determine the Best Available Control Technology for that component based on its fuel and operating characteristics. In general, low NOx burners, selective catalytic converters, low sulfur fuel, wet flue gas desulfurization, and good combustion practices are the expected emission control technologies for reducing NOx, SO2, CO, PM and PM10. Fabric filter baghouses and flue gas desulfurization are the expected control technologies for reduction of lead, mercury, beryllium, and fluorides.

- The air modeling analysis indicates that the concentrations of particulate matter, especially total suspended particulates (TSP 24-hour), PM_{10} (24-hour), and SO2 (both 3-hour and 24-hour) would increase at specific locations around the plant site due to operation of the ERGS. Several of these pollutant concentrations combined with the background concentration are approaching 100 percent of the National Ambient Air Quality Standard (NAAQS).. However, the results of the air quality impact analysis demonstrate that the ERGS meet the NAAQS, established to protect public health.

- PM_{10} (24-hour) would also consume nearly 100 percent of the PSD increment. However, increment impacts are very localized at specific locations around the plant site and are not regional in nature. The probability that a new PM_{10} source would impact the same specific locations at the Elm Road site is very remote. The PSD increment modeling results show that a new source located in Racine County would not have a measurable impact on the specific high increment locations around the Elm Road site. Therefore, the Elm Road Generating Station should not affect this new source or any other major source of PM from being able to obtain an air permit. [new]

- The air modeling analysis for the North Site indicates that the total concentrations of all pollutants, except the suspended particulates (TSP) emissions are at approximately 80 percent or less of the National Ambient Air Quality Standards, indicating that the project is be permittable. However, the concentration of total suspended particulates (TSP 24-hour) emitted from the ERGS would nearly double the background concentration of this pollutant and result in a concentration that is about 99.5 percent of the Wisconsin secondary (welfare-based) standard.

- At the South Site, the air modeling analysis based on a 470-foot stack height shows that a slightly higher level of TSP (99.8 percent of the NAAQS) and higher SO2 (3-hour and 24-hour) concentrations.

- An air quality modeling assessment of the potential impacts of the proposed Elm Road Generating Station as well as the multi-emission reduction agreements on regional ozone (1-hr and 8-hr) and fine particulate (24-hr PM2.5 and PM_{10}) standards was conducted by Alpine Geophysics and ENVIRON.

  The assessment concluded the following related to the possible impacts on ozone levels in the region:
  - Addition of the proposed new ERGS units by themselves, without the planned NOx reductions from the existing WEPCo facilities, would have minimal impacts on the regional 1 hour and 8 hour ozone concentrations, less than 1 ppb increases.
  - When adding in the emission reductions associated with the multi-emission agreements with DNR and with EPA , there would also be minimal impacts to regional ozone concentrations, The increases and decrease in the 8-hour ozone concentrations are generally less than 1 ppb.
  - In some isolated instances, PTF emission reduction measures produced small, less than 2 ppb increases in 8-hour ozone concentrations. These increases occur in isolated onshore areas, but they mostly occur over Lake Michigan away from population centers.

  For 24-hr $PM_{2.5}$, the air quality modeling assessment concluded the following:
  - Addition of the proposed new ERGS units by themselves, without the planned NOx reductions from the existing WEPCo facilities, has minimal impacts on 24-hr $PM_{2.5}$ concentrations in the region.
  - The modeling results indicate that when the occasional incremental increases occur, they are typically less than 0.5 µg/m^3 and primarily occur over Lake Michigan By contrast, when the PM2.5 analysis predicts concentration decreases to occur, the decreased concentration levels are on the order of 1 to 3 µg/m^3.

- An air quality modeling assessment of the potential impact of the proposed Elm Road Generating Station and existing Oak Creek units on local mercury deposition in Wisconsin was conducted by Scientists at Atmospheric & Environmental Research, Inc. The existing Oak Creek units were estimated to contribute about 2% to the total background Hg deposition in this region. The corresponding ratio of incremental local Hg deposition to background deposition is about 1% for the new ERGS units

- An air quality modeling assessment was conducted to determine whether Lake Michigan shoreline fumigation (lake breeze) would cause potential impacts on ground-level concentrations from the new Elm Road Generating Station and existing Oak Creek units. The results of the modeling analysis indicate that the proposed ERGS, in conjunction with the existing plant emissions and regional background concentrations, will not cause or contribute to an exceedance of the short-term ambient air quality standards for SO_2, PM_{10} and CO. Furthermore, the modeling analysis results indicate that ERGS will not cause or contribute to an exceedance of the PSD increments for SO_2 and PM_{10}

- The air modeling and PSD increment results demonstrates that ERGS meets the NAAQS and PSD increment. The information provided in the air permit application and in the environmental impact statement demonstrate that the ERGS project is permittable. A final determination will made after the requirements of Wis. Admin. Code ch. NR 150, the DNR WEPA rule, are satisfied

Table 12-1 Comparisons between the proposed power plant sites for public interest and environmental values

Siting Factor

North Site
Air Concentration of total suspended particulates (TSP 24-hr) would be 98.8% of the Wisconsin secondary air quality standard. PM_{10} concentrations would be about 82.6 % of the NAAQS.

North Site with Accommodations
Air Concentration of total suspended particulates (TSP 24-hr) would be 95.0% of the Wisconsin secondary air quality standard. PM_{10} concentrations would be about 81.6 % of the NAAQS.

South Site
Concentration of total suspended particulates (TSP 24-hr) would be 99.8% of the Wisconsin secondary air quality standard. SO_2 3-hour and 24-hour are 72.2% and 64.7% of the NAAQS respectively.

South Site-Exp
Concentration of total suspended particulates (TSP 24-hr) would be 99.8% of the Wisconsin secondary air quality standard. SO_2 3-hour and 24-hour are 72.3% and 65.4% of the NAAQS respectively.

Comment: Please consider the following clarifications to the DEIS Executive summary:

Air quality impacts

WE is proposing to install best available control technologies for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter less than 10 microns in diameter (PM_{10}), lead, mercury, fluorides, and sulfuric acid mist (H_2SO_4). In addition, Lowest Achievable Emissions Rate (LAER) controls are proposed for volatile organic compounds (VOCs).

In addition, best available control technologies and operating practices are proposed to control fugitive particulate emissions from the various material handling and storage processes.

The air modeling and PSD increment results demonstrates that ERGS meets the NAAQS and PSD increment. However, local air quality would be expected to be impacted as a result of constructing and operating the facility. Results of air modeling analysis indicate that the resultant concentration of total suspended particulates (TSP 24-hr) including the regional background would be nearly 100 percent of the Wisconsin secondary (welfare based) air quality standard. Concentrations of PM_{10} including the regional background are expected to be about 80 percent of the health-based National Ambient Air Quality Standard (NAAQS). The ambient air impacts of TSP and PM_{10} are very localized at specific locations around the plant site or along the railroad track that runs through the site and are not regional in nature.

PM_{10} (24-hour) would also consume nearly 100 percent of the PSD increment. However, increment impacts are also very localized at specific locations around the plant site and are not regional in nature. The probability that a new PM_{10} source would impact the same specific locations at the Elm Road site is very remote. The PSD increment modeling results show that a new source located in Racine County would not have a measurable impact on the specific high increment locations around the Elm Road site. Therefore, the Elm Road Generating Station should not affect this new source or any other major source of PM_{10} from being able to obtain an air permit

If constructed on the North Site with accommodations, the concentration of TSP would be a slightly lower percentage of the standard compared to the North Site without accommodations, and less of the expected increment for the 24-hour PM_{10} and 24-hour SO2 increments would be consumed.

An air quality modeling assessment of the potential impacts of the proposed Elm Road Generating Station as well as the multi-emission reduction agreements on regional ozone (1-hr and 8-hr) and fine particulate (24-hr $PM_{2.5}$ and PM_{10}) standards indicate that there would be minimal impacts on the regional 1 hour and 8 hour ozone and on the 24-hr $PM_{2.5}$ concentrations.

An air quality modeling assessment of the potential impact of the proposed Elm Road Generating Station and existing Oak Creek units on local mercury deposition in Wisconsin indicates that the existing Oak Creek Power Plant contributes about 2% to the total background Hg deposition. The corresponding ratio of incremental local Hg deposition to background deposition is about 1% for the new ERGS units

The air modeling and PSD increment results demonstrates that ERGS meets the NAAQS and PSD increment. The information provided in the air permit application and in the environmental impact statement demonstrate that the ERGS project is permittable. A final determination will made after the requirements of Wis. Admin. Code ch. NR 150, the DNR WEPA rule, are satisfied